D3.2 Developments affecting the design of short-term markets

Luis Olmos, Pablo Rodilla, Camila Fernandes, Pablo Frias, Aurèle Fontaine, Ricardo Loureiro, Bruno Caetano, Sophie Dourlens, Thomas Döring, Ove Wolfgang, Howard Wright, Yves Langer, Bettina Burgholzer, Ivan Pineda, Paul Wilczek, Plácido Ostos, . Manoël Rekinger. Colas Chabanne

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MAIN AUTHORS

Name	Organisation	E-mail
Luis Olmos	Comillas	luis.olmos@iit.comillas.edu
Pablo Rodilla	Comillas	pablo.rodilla@iit.comillas.edu
Camila Fernandes	Comillas	camila.fernandes@iit.comillas.edu
Aurèle Fontaine	RTE	aurele.fontaine@rte-france.com
Bruno Caetano	FOSG	bruno.caetano@ren.pt
Ricardo Loureiro	FOSG	ricardo.loureiro@ren.pt
Yves Langer	APX	Y.Langer@apxgroup.com
Howard Wright	APX	H.Wright@apxgroup.com
Sophie Dourlens	Technofi	sdourlens@symple.eu
Ove Wolfgang	SINTEF	Ove.Wolfgang@sintef.no
Bettina Burgholzer	EEG	<burgholzer@eeg.tuwien.ac.at
Thomas Döring	Solar Power Europe	t.doering@solarpowereurope.org
Ivan Pineda	EWEA	Ivan.Pineda@ewea.org
Plácido Ostos	Iberdrola	postos@iberdrola.es

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Executive Summary

Integrating large amounts of RES generation will necessarily have a large impact on the functioning of system due to the intermittent nature of a large fraction of this generation. Then, besides those products traditionally provided through markets, like energy or balancing reserves, others, like firm capacity, may need to be explicitly provided through markets as well. Besides, markets shall need to become wider, integrating local (national) ones in order to increase their efficiency and promote fair competition. Last, but not least, all these market developments must be made compatible with the deployment of large enough amounts of RES generation. This may require providing a specific treatment to this kind of generation in markets.

Obviously, the aforementioned changes in the organization and nature of markets will impact the functioning of long term ones. However, short term markets will certainly have to undergo some changes as well if authorities want to achieve a satisfactory functioning of the system from the economic, environmental and reliability points of view. Thus, balancing markets, day-ahead and intraday energy ones will have to be integrated at European level and accommodate both RES generation and demand. Besides, the efficiency of the functioning of these markets will have to be preserved in the new context. This report is concerned with the definition and conceptual assessment of main possible options for the design of those short term markets that will be needed, as well as with the analysis of the short term effects that other markets may have.

Market design aspects studied

Main aspects of the design of short term markets, and long term ones with an impact on the shorter term, that are discussed include the following:

- **Model to be used for the representation of the network in short term markets.** Options for this include the use of nodal, zonal or hybrid zonal prices, or the implementation of a single node dispatch.
- **Design of the timing of the sequence of short term markets.** This is concerned with the timing of all the sequence of actions to be taken to run a market and the chronological order and distribution in time of these markets.
- **Format of bids to be submitted to energy markets and rules for the computation of prices in them.** Bids to be submitted may be more complex and flexible, or instead simpler. Prices computed may be focused on accurately representing marginal costs or allowing the recovery of costs incurred by agents.
- **Design of balancing markets.** Here, relevant issues concern the design of the provision of balancing services, considering the possible bundling of products; the design of prices applied to Balancing Responsible Parties (BRPs) reflecting their responsibility in incurred costs; of the interaction among balancing markets and others, as well as the interaction across regions.
- **Short term effects of the implementation of markets supporting the deployment of renewable generation.** Regarding this issue, possible RES support schemes analyzed should include market based as well as administrative ones; quantity and price based schemes; and those where support payments earned by RES generation are set in the long term, as well as those where payments are only set according to the output of short term markets.
- **Integration of demand in short term markets, and mechanisms to be implemented in order to achieve this.** These mechanisms include both implicit and explicit ones; and

consider also several options for the contractual arrangements among stakeholders in the system (consumers, suppliers, and possible load aggregators).

Criteria to assess market design options

Design options related to all the aforementioned aspects of the functioning of markets are analyzed according to a set of assessment criteria. These criteria are related to main objectives to be achieved by markets. A list of the main criteria follows:

- **Economic efficiency criteria**, which are concerned with achieving a market dispatch involving the most cost competitive agents compatible with preserving the secure system operation, as well as with the application of price signals that drive a cost competitive, reliable, and environmentally friendly, development and operation of the system in the long and short term. Aspects included within these group of criteria concern the **marginal costs reflectivity of prices**, the **liquidity** achieved in markets, the **coordination** achieved in the functioning of markets across time frames and geographical areas; or the **effectiveness** of markets in achieving the objectives they have been designed for (like the procurement of certain products).
- **Robustness**: this is concerned with the ability of markets to produce a consistent, satisfactory outcome across a wide range of situations.
- **Criteria related to the implementability of markets**, or the easiness of implementation of markets analyzed in the European context envisaged in the medium to long term future. Here, aspects like the **experience** with the organization of markets, the **compatibility** of these markets with established European principles, the **complexity** and **transparency** of markets, and their **replicability** in other time frames, have a large importance.
- **Fairness criteria**, which assess the ability of market design options to avoid what is perceived in Europe as the unfair discrimination of some stakeholders.

Result of the assessment: most promising market design options

Considering the aforementioned options for the implementation of markets, and according to criteria just outlined, the most promising options have been identified and their selection has been argued. In the next paragraphs, most promising options for the organization of each aspect of the functioning of markets are pinpointed, and reasons for having selected them are provided.

As far as the **representation of the network in markets** is concerned, the preferred options are Zonal and Hybrid zonal pricing. The application of both should result in a large enough liquidity in markets, given the large number of active market players that should exist within price zones to be defined. Besides, the computational burden of computing the dispatch under both schemes should be smaller compared to other options like Nodal pricing. Given that infeasibilities resulting from the zonal dispatch should be limited, Zonal, and Hybrid zonal network models could be considered as well in very short term markets. Prices computed are close to marginal supply costs under Hybrid zonal pricing, while they are less efficient under Zonal pricing. On the other hand, large experience exists about the implementation of Zonal pricing.

Other options that rank very high according to some criteria, like Nodal pricing under marginal cost reflectivity, perform poorly for other criteria. Thus, the liquidity of markets under Nodal pricing may be quite low in some areas, leading to the exercise of market power (MP) and non-reliable prices.

The **timing of markets** should be modified to allow their outcome to react faster to changes in system conditions largely caused by renewable generation. Then, day-ahead markets should be called as late as possible (regarding bid submission) while tasks associated with them should be carried out as quickly as possible. In the Intra-day time frame, continuous trading, providing greater flexibility, should be implemented, while in those cases where flexibility is not enough this should be combined with discrete auctions.

Options for the procurement of balancing reserves from the long to the very short term should be made available to allow all types of resources to contribute reserves to the extent of their possibilities. Lastly, the gate closure should be taken as close as possible to real time, providing, again, more flexibility.

Regarding the **energy pricing and bidding protocols**, the EU approach turns out to be most efficient, since prices computed more closely reflect marginal supply costs incurred. On the other hand, the US approach features more flexible bids that can reflect power plant constraints and provides larger certainty of producing a market price and a feasible market dispatch, which is not guaranteed under the EU approach. Given that both approaches have some advantages and disadvantages, preserving the EU approach within Europe seems sensible, thus avoiding large implementation costs, and major changes in market design, which would require a large consensus and would be difficult to achieve.

As for **balancing markets**, more competition would be achieved if both capacity and energy products and upward and downward reserve are separately procured, all technologies are allowed to participate, minimum size requirements for bids are removed (or aggregation is allowed to take place) and pricing of products is marginal.

Regarding the imbalance settlement rules, if balancing arrangements applied are well suited to single pricing, this settlement scheme should allow prices to reflect the costs imposed on the system by any imbalance and should avoid creating a surplus for the system operator (SO) out of the application of the scheme. However, if balancing arrangements do not suit single pricing, this may produce worse results than dual pricing. The settlement period should be as short as possible for imbalances created by each agent to be reflected in payments to be made by it.

Lastly, imbalance actions should take place after intra-day markets and the use of balancing resources for congestion management and balancing purposes should be kept separate regarding the price formation process.

RES support schemes applied should allow an effective and efficient functioning of short term markets. This is the case of long term clean capacity auctions, mainly, but also, to some extent, that of long term clean energy auctions, certificate schemes and feed-in-premium (FIP) ones based on auctions. The distortion of efficient short term prices caused by long term capacity auctions is negligible, and it may be limited for the rest of these schemes. Being market schemes that make revenues of RES operators depend on operation decisions, these support options foster the participation of RES generation in short term markets and are difficult to be manipulated by authorities. Lastly, Certificate schemes allocate the costs of RES support to agents responsible for the need to deploy this generation, i.e. consumers.

These are the preferred RES support schemes considering also their long term effects, since they are effective in achieving the deployment of RES generation, and this should take place at low cost, since also the long term signals they produce are efficient.

Lastly, regarding **Participation of demand in short term markets**, all options available, both implicit and explicit schemes, should be allowed to provide consumers with large flexibility. Implicit schemes are the simplest ones and reasonably efficient. However, under these schemes, agents cannot compete to access demand side response (DSR) resources. Then, the implementation of independent load aggregators should also be considered as an option. The transfer of funds between aggregators and suppliers should be set by an independent entity for the treatment to both of them to be fair and in order to promote efficiency in market functioning.

Abbreviations

aFFR – automatically activated Frequency Restoration Reserves

AASS – Ancillary Services

BRP - Balancing Responsible Party

BSP - Balancing Service Provider

CFD - Contract For Difference

CRM - Capacity Remuneration Mechanisms

CWE - Central-West Europe

DA - Day-Ahead

DSO - Distribution System Operator

DSR – Demand Side Response

EC – European Commission

ETS – Emissions Trading System

EU – European Union

EUPHEMIA - pan-EUropean Hybrid Electricity Market Integration Algorithm

FB - Flow-Based

FG EB - Framework Guidelines on Electricity Balancing

FIT – Feed-in Tariff

FIP – Feed in Premium

FCR - Frequency Containment Reserves

FRR - Frequency Restoration Reserves

ID - Intraday

IEM - Internal Energy Market

ISO – Independent System Operator

ISP - Imbalance Settlement Period

mFFR – manually activated Frequency Restoration Reserves

MCP – Marginal Cost Price

MP – Market Power

MRC - Multi-Regional Coupling

NC CACM - Network Code on Capacity Allocation and Congestion management

NC EB – Network Code on Electricity Balancing

NTC - Net Transmission Capacity

OTC - over-the-counter

PCR – Price Coupling of Regions

PABs - Paradoxically Accepted Bids, or Blocks

PPAs- Power Purchase Agreements

PRBs - Paradoxically Rejected Bids, or Blocks

PX – Power Exchange

RES – Renewable Energy Sources

RES-E – Electricity from Renewable Energy Sources

RR - Replacement Reserves

RT - real-time

RTO – Regional Transmission Organization

SCUC - Security Constrained Unit Commitment

SO – System Operator

SoS – Security of Supply

TM – Target Model

VG –Variable Generation

VRE - Variable Renewable Energy

WP – Work Package

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1 Introduction

This report provides the assessment made within the Market4RES IEE project of the design of pending market developments required to achieve a satisfactory functioning of European electricity systems in the short term. Thus, not only market structures required for agents to participate in short term markets are analyzed. Besides, the effects on the short term system functioning are assessed, including the functioning of short term markets, that the main regulatory developments may have.

This report is produced within the WP3 of the project, focused on the conceptual assessment of possible design options for market developments that will most probably be implemented in the future. Both market arrangements and the possibility of the implementation in the short and the long term are analyzed. The implementation of market developments, which have been identified as necessary in the diagnosis analysis (carried out within WP2) are investigated in this report.

Out of the conceptual analysis related to the short term of design options for regulatory (mainly market) developments reported here, most promising options are identified. They are to be investigated further in subsequent analyses, of a quantitative nature, within the project. These quantitative analyses are partly to take place within WP4, for those design options whose implementation is feasible in the short term (up to the year 2020), and partly within WP5, for those other options that can only be implemented in the long term, as well as for the effects of all promising design options on the functioning of the system beyond the year 2020. Conceptual analyses reported in D3.1 and D3.2, together with quantitative ones in WP4 and WP5, should allow defining the changes which have to be made to long and short term markets in order to achieve a satisfactory functioning of the European electricity system in a context characterized by the existence of vast amounts of RES generation.

Therefore, the conceptual analyses reported within D3.1 and this report (D3.2) play a central role in bridging the gap between the diagnosis of the current situation and the expected evolution of European electricity systems and markets, and the definition of recommendations on the specific “treatment” to be given to markets to improve their outcome.

Some of the aspects are related to the design of specific short term markets. A list of the main topics directly related to short term market design follows:

- **The consideration of the regional transmission network (of a cross-border nature)** in short term markets, mainly energy ones. Here, the modeling of grid congestion must be made compatible with socio-political constraints imposed on electricity markets and challenges related to the development of limited competition in some areas within Europe.
- **The design of the sequence of short term markets** from some days ahead of system operation up to real time; where flexibility provided by very short term markets must be made compatible with the need for market and system operation authorities to have enough time to implement the outcome of markets while preserving the safe operation of the system.
- **The design of balancing markets** in an international context where several national systems may interact in this regard; where balancing accountability and balancing service provision must be organized in an efficient manner in an international context.
- **The design of the participation of consumers in markets** of a short term nature, like balancing or short term energy ones. In this case, both implicit and explicit schemes for

the adaptation of the behavior of demand to system conditions within the framework of short term markets are investigated.

- Lastly, **bidding protocols** are assessed to decide on the right balance between the flexibility made available to market agents by complex bids in short term markets, which should allow them to reflect their operation constraints, and the liquidity and other advantages provided by simpler market bid formats. As a complementary topic, the format of prices computed in markets and applied to products traded is also to be investigated to consider, among other things, the use of side payments complementing marginal ones.
- Besides, there is room to investigate other topics under this task that do not specifically concern short term markets, but rather the short term effects of schemes applied either in the short or the long term. This is the case of **schemes implemented to guarantee a large enough deployment of RES generation**, which will impact both the development of the system, as reported in D3.1, and the short term, as we discuss here.

All the before-mentioned market designs are discussed in the following sections of the document, which conclude with a recommendation of the options to be further investigated in WP4 and WP5. Lastly, section 8 concludes.

2 Network representation

Here the aim is to ascertain the appropriateness of the granularity and features of the network model considered in the computation of the outcome of short term markets, and the transmission capacity allocation method applied in market clearing algorithms, regarding their impact on the energy dispatch and electricity prices applied. Energy (offer) dispatching and price computation are aspects of the functioning of markets that are very much interrelated. Therefore, they should be dealt jointly. There is a diversity of possible combinations of implemented solutions for:

a) The granularity of the considered network model in the energy and capacity dispatch;
b) The granularity of the considered network model for energy pricing;
c) and the allocation of transmission capacity.

This should be reflected in the range of design options considered in the analysis.

A distinction must be made between the analysis of long term cross-border products (considered in D3.1 "Developments affecting the design of long-term markets"), and the analyses reported here. In this report, the focus is on the short and long term effects of the consideration of the grid in the short term energy dispatch.

2.1 Design Options for the representation of the network in markets

This section provides a description of the most representative options that can be considered for the representation of the network in markets. Together with options, their main features are provided. These features include:

- level of accuracy (detail) of the grid representation in the generation dispatch;
- level of detail of the grid representation in the price computation;
- level of granularity of price signals;
- compatibility with currently existing bidding zones;
- and stability in time of price zones defined.

2.1.1 Nodal pricing

This involves the computation of a separate price in each node of the network reflecting the marginal cost of supply of an extra unit of power in this node.

Consideration of the grid in the generation dispatch

Full consideration of the grid. Generation dispatched compatible with all network constraints.

Consideration of the grid in price computation

Full consideration of network constraints in prices (potentially).

Level of granularity of price signals

Prices differentiated at node level, reflecting marginal nodal supply costs.

Compatibility with currently existing bidding zones

Not compatible with bidding zones. This concept should be discarded (potential use for the collection of bids).

Stability in time of price zones defined

No price zones defined. Price zones defined always coincide with nodes.

2.1.2 Zonal pricing

This involves the consideration of zones within the network that may or may not take into account political borders that exist. An example of this is the flow-based network model considered for the management of congestion in most of Europe, where zones defined coincide in most cases with countries. Given that the outcome of the dispatch may not be feasible if intra-zonal congestion exists, redispatching some generation units, i.e. modifying their schedule, may be necessary.

This method is similar to the flow-based congestion management approach currently being applied in Central-West Europe (CWE), though in the latter, some specific network congestion occurring within an area may be considered as well when computing the dispatch.

Consideration of the grid in the generation dispatch

If price zones defined do not coincide with existing political/electrical divisions, defining a new aggregate model of the grid would be necessary. The price zones applied may or may not be fixed/predefined. If price zones change with congestion occurring in the nodal grid, most relevant transmission grid constraints (the active ones where congestion has a highest system cost) should be considered when computing the generation dispatch. Considering all major system congestion when zones are fixed could potentially involve the definition of a very high number of zones, which may not be feasible.

The grid model used to compute power flows in the system may consider the application of both the 1st and 2nd Kirchhoff law (DC model) or only the first one (transport model of the grid, where corridors among zones are considered as pipelines with a certain transfer capacity). The network considered in the generation dispatch includes a medium level of detail.

Even if the full transmission grid is considered when defining zones in the network model, i.e. when building the network model, not all grid constraints are considered when computing the energy dispatch and energy prices. Only constraints limiting power exchanges among zones are considered in the energy dispatch and to compute prices.

Consideration of the grid in price computation

Prices applied aim to reflect marginal supply costs in each price-zone. Marginal supply costs in a zone are influenced by network constraints, but also by fuel (or primary energy) costs, among other factors. Congestion rents result from price differences among zones caused by constraints affecting the level of power exchanges among these zones. These inter-zonal constraints must be related to the congestions actually occurring in the nodal grid. Rents amount to the product of the aforementioned price differences among zones and power exchanges taking place among the same zones. If congestion zones (price zones) are not defined a priori (i.e. if they are not fixed), differences in zonal prices may appropriately reflect any major congestion occurring in the system. In order for this to happen, the boundaries of price zones considered in each snapshot, or set of snapshots, must be adapted to conditions applying in this snapshot, so that major active constraints on power flows in the nodal transmission grid are only limiting power exchanges among zones, and not power exchanges among nodes within any given zone. This approach is only valid if, as a result of the application of this scheme to define zones in each snapshot, a small enough number of price zones is defined over the whole year.

Level of granularity of price signals

The level of granularity of prices is intermediate. Intra-zonal congestion is not considered in price calculation. If areas are to appropriately reflect congestion in a meshed grid, or congestion in the grid changes significantly across snapshots, the number of price zones to define may be very large. Defining a limited number of areas may thus be challenging.

Prices paid by consumers may be the same for all of them. Then, a single price is levied on consumers resulting from weighting in prices earned by generators in price zones with the amounts of power produced in these zones.

Compatibility with currently existing bidding zones

If zones adapt to the pattern of network congestion, this scheme may probably be incompatible with current practice since, generally, zones to be defined according to efficiency criteria do not coincide with control zones or political borders. Thus, in that case this scheme could face significant opposition.

Stability in time of price zones defined

Full stability of price zones if these zones are pre-defined. If zones are adapted to existing congestion, the zones may vary across snapshots.

Normally, price zones are defined according to structural congestions. Then, they are defined once and for all, i.e. they are fixed. But this is only valid if a clear, systematic pattern of congestion exists throughout the year.

2.1.3 Hybrid zonal pricing (zones are subdivision of control areas)

Under this scheme, zones are defined for pricing and congestion management. However, political borders are considered to define a finite number of zones within each national system. This is the scheme currently implemented in Italy or the Nordic countries.

Consideration of the grid in the generation dispatch

The consideration of the grid in the generation dispatch is analogous to under zonal pricing, though zones in the latter may be divided further into additional zones in the hybrid scheme. An example of this is the so-called area pricing approach applied in the Nordic system, whereby price zones considered are fixed. In this case, given that the number of zones defined is larger than under zonal pricing, even if zones are predetermined, the range of systems where major congestion is reflected in the generation dispatch and prices may be wider. Of course, not all grid constraints are considered when computing the energy dispatch and energy prices. Only constraints limiting power exchanges among zones defined are considered in the energy dispatch and to compute prices.

Consideration of the grid in price computation

The consideration of the grid for price computation under this scheme is completely analogous to that in the zonal pricing scheme. However, as explained in the previous paragraph, given that the number of zones defined may be higher than under zonal pricing, reflecting major congestion in prices may be in this case possible in a wider range of systems.

Level of granularity of price signals

The level of granularity of prices is intermediate. Intra-zonal congestion is not considered in price calculation. If the system grid is meshed, or the identity of congested lines varies across snapshots, appropriately representing congestion requires, either defining a large number of price zones, or changing the set of price zones considered from one snapshot to another. None of these two options is normally easily accepted by authorities. Defining a limited number of fixed price areas that make an efficient network model may thus be challenging, if not impossible.

Given that zones defined under hybrid pricing must be a subdivision of existing control areas or countries, the number of zones defined may probably be larger than that under the general zonal-pricing approach for the same level of efficiency in the dispatch. Presently, there are 13 price areas in the Nord Pool region. Transfer capacities among these areas are given by the system operators before the market agents submit their bids. Then, Nord Pool Spot calculates zone prices.

Under a hybrid scheme, as for a zonal one, prices paid by consumers may be the same for all of them. An example of this practice is the National Single Price (PUN) in Italy.

Compatibility with currently existing bidding zones

It may be compatible with current practice if price zones are chosen to coincide with control areas or countries. However, making the corresponding dispatch feasible may cause a significant loss of efficiency with respect to the solution of the economic dispatch computed considering the whole transmission grid. Dividing existing control areas or countries into several price zones, as may probably be advisable for efficiency purposes, would be against current practice in most systems and could face significant opposition.

Stability in time of price zones defined

Again, this scheme is similar to zonal pricing in this regard. Full stability of price zones exists if the zones are pre-defined. If zones are adapted to existing congestion, they may vary across snapshots. Normally, price zones are defined according to structural congestion. Then, they are defined once and for all, i.e. they are fixed. But this is only valid if a clear, systematic pattern of congestion exists throughout the year.

As argued above, given that the number of zones to be defined under hybrid-zonal pricing tends to be higher than under zonal pricing, considering a fixed set of zones that appropriately reflects congestion may be feasible for a larger number of systems than if zonal pricing is applied.

2.1.4 Single node dispatch + redispatch

Under this scheme, the original energy dispatch is computed disregarding the existence of the network. This results in a single energy price at system level. Then, changes are made to the original dispatch to get to a situation where it is compatible with network constraints (is feasible). This changes, known as re-dispatch, affect the price of constrained-on and constrained-off generation, but not the system price previously computed.

Consideration of the grid in the generation dispatch

Grid constraints are not considered when computing the economic energy dispatch. They are only considered afterwards when deciding which changes have to be made to the original dispatch to obtain a feasible one. These changes may be decided according to several possible criteria: 1) minimizing the differences between the final and the original program of power plants; 2) minimizing the cost of the redispatch (difference between the amount paid to constrained-on generators and that collected from constrained-off generators), etc.

Changes to the original program of units result from the System Operator buying a certain amount of power in importing areas and selling a certain amount of power in exporting areas in order to create counter-flows that, together with original flows, result in net flows that are compatible with network constraints.

Consideration of the grid in price computation

A single energy price is computed and applied at system level, which results from the unconstrained energy-dispatch. Only those generators that are constrained-off or constrained-on in the redispatch process earn prices that differ from the former and somehow reflect active network constraints. Constrained-off generators should not earn anything, i.e. they should not be compensated for being left out of the final dispatch. Constrained-on generators may earn pay-as-bid prices or marginal prices bid in the redispatch process. The net economic cost of the redispatch may be charged to the rest of generators in the system, to those generators that are deemed responsible for congestion in the system, to consumers, or to both generators and consumers. Thus, generally speaking, the resulting prices do not reflect marginal supply costs in each zone of the system.

Level of granularity of price signals

Price signals earned by the majority of generators are not differentiated by location in the grid. All generators earn the same price. Only those generators directly involved in the redispatch process earn prices that depend on their location in the grid.

Compatibility with currently existing bidding zones

The congestion management scheme applied and electricity prices computed are fully compatible with currently existing bidding zones. Redispatching is currently being applied in most systems in the world.

Stability in time of price zones defined

There are no price zones defined.

2.1.5 Full network representation + average zonal prices

The dispatch is computed taking into account the full grid and all network constraints. Nodal prices are computed based on this dispatch. Then, for flexible load and for generation, pay-as-bid pricing is applied. For inflexible load, prices applied are computed as the average of nodal prices per zone.

Consideration of the grid in the generation dispatch

A full-fledged model of the grid is considered when computing the energy dispatch. Then, all relevant network constraints (including all network congestion) are considered when computing the level of production of power plants. Then, a single price is computed for each of a set of zones and applied to inflexible load. This results from computing the weighted average of prices for all the nodes within this zone. Weighting factors normally are proportional to the amount of demand and/or generation dispatched in nodes.

Consideration of the grid in price computation

All network constraints are considered in nodal price calculation. However, zonal prices finally applied, resulting from averaging nodal ones, do not reflect congestion in the grid within each area.

Level of granularity of price signals

The level of granularity of price signals is medium, since a single price is applied within each zone.

Compatibility with currently existing bidding zones

Price zones may be defined to coincide with currently existing control areas or countries. Then, price zones are compatible with bidding zones. Alternatively, price zones may be chosen to reflect grid congestion occurring in each snapshot. In this second case, price zones may not be compatible with already existing bidding zones.

Stability in time of price zones defined

Full stability of price zones exists if these zones are pre-defined. If zones are adapted to existing congestion, they may vary across snapshots.

2.2 Assessment criteria

In the next paragraphs, the assessment criteria considered for the comparison of the performance of several design options are identified and briefly described.

2.2.1 Efficiency

This group of criteria concern the impact that the considered network model, and the applied capacity allocation method, in the short term have on the overall social welfare both in the short term and the long term. The overall welfare can be measured as the market welfare minus the redispatch costs. An example of the impact that the consideration of the network in the short term dispatch has on system welfare is the fact that the larger the considered zones in the market dispatch are, the higher the market welfare is; but at the same time the redispatch costs are higher. Overall, net system welfare may probably decrease with the size of areas.

Marginal cost reflectivity resulting from the granularity of the network model

The system of prices applied should reflect local marginal short term supply costs in each node of the system. This should encourage market agents to make efficient long and short term decisions, and would, therefore, ensure the compliance of commercial positions by agents with technical constraints imposed by the network. Depending on the grid architecture and pattern of congestion, this may result in the need to separately compute a price for each node, or the possibility to define homogeneous prices within each set of zones. Thus, computing average prices per area may be accurate enough or not depending on the features of the system considered.

Level of coordination of the capacity allocation method applied

A flow-based scheme, as defined in the target model (TM), should be applied in order to achieve an efficient coordination of the allocation of transmission capacity across all congested corridors in the system. This is in contrast with the Coordinated Net Transmission Capacity (NTC) approach defined also in the TM documents. In the latter, scarce transmission capacity is allocated to pairs of bidding zones in a predefined way, rather than according to the value that transactions among these pairs of bidding zones put on that capacity.

Market (network) modeling imperfection costs

Some network modeling solutions do not include all constraints imposed by the real network. Then, the market outcome resulting from considering such a network model may not be feasible. Modifying the market outcome to make it feasible results in efficiency losses, which correspond to a decrease in the overall system welfare. In some cases, efficiency losses are caused by the fact that the granularity level of the network model considered is not high enough to accurately represent congestion in it.

Liquidity

Local relevant markets created when considering network constraints should not exhibit liquidity problems, i.e. a large enough number of bids and offers should be involved in the determination of the market price in each area defined (or node, under nodal pricing). This shall enhance competition in markets, fight the exercise of market power (MP) and result in prices that are stable. Liquidity is larger the lower the level of granularity of network models considered in the dispatch and energy pricing.

2.2.2 Robustness

Prices computed should always reflect marginal costs in nodal pricing schemes regardless of system conditions applying in each time. On the other hand, when zonal prices are computed, their efficiency may decrease with the passing of time if the definition of these zones is not updated periodically. Then, the robustness of the market solution may be larger if there is no need to define zones.

2.2.3 Implementability

Computational feasibility

The larger the number of network areas considered, the larger the computational complexity. However, considering even thousands of nodes/areas should be possible, since it has been applied in other regions in the world (for instance in PJM[1]).

Compatibility with existing regulation in Europe

Implementing a system of prices that is in line with principles widely implemented in the Internal Energy Market (IEM) or European legislation, like zonal pricing, would face less opposition than schemes that are against these principles.

Simplicity (Conceptual one)

The simpler the functioning of a market is to understand, the more predictable its output will be, and, therefore, the easier its acceptance by parties will be.

Implementation costs

Costs of implementing a nodal network model may generally be higher than those of implementing a zonal one, since, for example, software used may need to change and the amount of information exchanged will increase substantially. Besides, implementing a zonal scheme where zones do not coincide with currently existing ones may require the change of the footprint of local power exchanges or aggregators, and the structure of the communication and control scheme adopted (generators and demand initially reporting to some control centre may start reporting and communicating with a new one).

Experience with its implementation

Authorities and systems tend to rely more easily on schemes that have been widely applied.

Possible extension to several time frames (scalability, replicability)

If possible, the system of prices devised (level of price differentiation by location) should be implementable not only in day-ahead markets, but also in other time frames (intraday, balancing energy, etc.).

2.2.4 Fairness

Distributive effects

Each studied design option may significantly impact the distribution of the social welfare between consumers and network owners (earning congestion rents, if private), and among the agents within each of these two groups, as well as among countries or areas in the system. Applying

[1] See www.pjm.com.

different prices on generators and consumers, or on different groups of agents of the same type, may be deemed unfair.

Compatibility with the application of single price to small consumers within a region, or country

It is widely believed that small consumers should not pay different prices if located in different areas within the same region. A scheme of prices that is compatible with this would be perceived as fair. Small consumers are perceived not to be able to properly manage the risk associated with changes occurring in the treatment given to them according to their location.

Transparency

In order for agents to be in the same conditions to participate in a market, rules should be well known by everybody.

2.3 Assessment of design options for network representation

In the following, we apply the grades **Very good**, **Good**, **Fair**, and **Poor** to rate the performance of each of the options that have just been defined for the representation of the grid in short term markets and assessment criterion considered. A "**+**" sign (respectively a "**-**" sign) indicates a grade between the grade shown and the next better (respectively lower) grade. For the criterion 'level of coordination' the grades used are **Very high**, **High**, **Moderate** and **Low**.

Note also that the result of the final assessment of an option by no means is the average of the grades obtained for all criteria, as a poor evaluation for one criterion may disqualify this scheme entirely. Moreover, some criteria may be more important than others.

2.3.1 Efficiency

Marginal cost reflectivity

In **Zonal pricing**, the net supply curve within each zone is built up from the existing offers and bids within this zone independently of the geographical location of generation and demand within this zone. Net supply curves per zone shall be considered together with network constraints to compute power exchanges among these zones. For a given set of exchanges among zones, the price is then determined as the highest offer (and marginal cost) that must be accepted to yield sufficient supply in the zone. In other words, the price in each zone is typically set equal to the most expensive accepted offer required to supply load in the corresponding zone. This is supposed to represent the corresponding marginal supply cost. However, differences in the marginal supply cost within each zone are not reflected in prices. This is especially critical in Europe, where defining large enough zones within which no relevant congestion exists may prove to be very challenging. Then, the grade for this option is **Fair**.

The marginal pricing principle is also applied under Hybrid zonal pricing and in the Single node dispatch + re-dispatch. The only difference among all these schemes in this regard lies in the size of considered zones in the clearing process, which is larger than under zonal pricing for the single node dispatch and smaller for hybrid zonal pricing. Prices in the latter case are more appropriate to reflect spatial differences in marginal supply costs. Then, the grade for **Hybrid zonal pricing** is **Good**, while the grade for the **Single node dispatch + re-dispatch** is **Poor**.

As explained previously, **Nodal prices** are shadow prices computed in an optimization problem where total costs are minimized. Thus, under this scheme, differences in local cost structures, and marginal costs, are reflected through the computation of differentiated prices with high granularity. An important obstacle for implementing nodal pricing in practice is the possible increase in the level of market power by agents that this scheme may create, and its misuse. Under this scheme, many producers could create shortages locally if they tried to increase local prices. By cutting back supply, or through bidding above marginal costs, producers could then obtain high nodal prices and high profits. However, this issue is considered in the criterion "Liquidity". The grade of this option is <u>Very good</u>.

Under **Average zonal pricing**, nodal prices are first calculated. However, flexible bids (producers and consumers) that are dispatched receive a pay-as-bid price, while inflexible load pays average zonal ones. If bids are built based on own marginal production costs, these costs will be reflected in the computed price. Then, prices earned would not reflect local marginal supply costs except for those generators and demands that are marginal. In the case of the latter, their flexibility would probably be partially used. However, agents in the system may adjust their bids to local marginal supply costs to increase their revenues or decrease their purchase costs. Then, generators have an incentive to increase their price offer above marginal production costs, which may lead, when not accurately predicting the local marginal supply costs, to these generators not being dispatched even when being cost competitive, and, therefore, to a loss of the efficiency of the dispatch. This loss of efficiency may be significant. Thus, **prices for generators** should be considered only <u>Fair</u>, while **prices for flexible consumers**, normally being at the margin, could in principle be deemed <u>Good</u>. Inflexible demand should pay the average nodal price in the corresponding zone, where nodal prices reflect marginal costs in each node of the area. This would be efficient if zones do not have relevant internal congestion, cf. discussion about zonal pricing. The grade of energy pricing for **non-flexible consumers** under average zonal pricing is <u>Fair</u>.

However, this dual price system for consumers may give adverse impacts on the willingness to bid in energy and flexibility. Pay-as-bid pricing for flexible consumers and average zonal pricing for inflexible ones may create incentives for some of both types of consumers not to bid according to the marginal value that electricity has for them, in order to decrease their energy purchase costs in the first case, and avoid being charged a price above the utility that electricity has for them in the second case:

1. According to this scheme, flexible consumers located in nodes where marginal supply costs are higher than average ones within their zone would have to pay high prices (the one they have bid). However, if these consumers withdraw all flexibility in their bids, they would get the lower average zonal price instead. This gives inefficiency in the short term dispatch, while the calculated nodal price does not reflect flexible consumers' willingness to pay. Furthermore, this gives inadequate long-term signals for investments in demand flexibility. Note that nodes where supply is expensive are precisely those where there is a highest demand for demand flexibility.
2. The second effect results from applying an energy pricing scheme to non-flexible consumers that is not consistent with the energy dispatch (which considers all system

constraints). Non-flexible consumers that are in this situation may bid a price below the real value that electricity has for them in order not to be dispatched.

Pricing of energy for consumers in the latter two situations should be deemed Poor. The overall grade for **Average zonal pricing** is Fair.

Level of coordination

In a **Nodal pricing** system, a central calculation and dispatch has to be carried out. This would then be on one extreme with respect to the level of coordination of capacity allocation in the market. Its grade is Very high.

In a system where a single price is applied (**Single node dispatch + re-dispatch**), there is no need for coordinating transmission capacity determination and allocation in the day-ahead market, since network bottlenecks are not considered in the calculation of the equilibrium price, regardless of power exchanges taking place among areas in the system. Then, the grade of this option is Low.

If **Zonal pricing** is applied, the capacities of the links among the zones defined must be determined and this capacity must be allocated to transactions. Here, we need to consider three relevant factors:

- the size/number of zones;
- how meshed the grid comprising inter-zonal links, i.e. the zonal network model, is;
- and the methodology for determining the available capacities on links and allocating them to agents.

Determining and allocating capacities using a Flow-based methodology involves a higher level of coordination than the NTC approach. After all, the amount of transmission capacity in each link allocated through the former methodology to transactions between each pair of zones is computed considering the impact on flows on this link and value placed on this capacity by transactions taking place between any pair of zones. On the other hand, in the NTC approach capacities of links are allocated to transactions among pairs of zones in a predefined way. As aforementioned, the NTC approach is supposed to be applied mostly in radial systems, where the potential benefit of applying a flow-based approach is smaller.

If there are only a few price-zones and zones are connected through radial links, inter-zonal capacities may be allocated to transactions between pairs of neighboring zones with limited need for coordination. Then, the NTC approach can be applied. However, if price-zones are many/small (cf. also hybrid zonal pricing) and/or connections among them make a meshed interconnection grid, the need for coordination in the allocation of capacity increases. For meshed grids, transactions among any pair of areas in principle affect the flow on other interconnection links. Then, the Flow-based approach should be applied. Thus, under zonal pricing, the coordination level needed varies with the price-zone configuration (number of zones and topology of the zonal grid model).

Zonal and **Hybrid zonal pricing** mainly differ in the number of zones considered. For zones of the size of TSOs, unless zonal network models are completely radial, there is a high probability that transactions within zones create loop-flows, i.e. flows on the inter-zonal links. Flows created by intra-zonal transactions cannot be represented in a zonal model and therefore, cannot be taken into account for congestion management. This means that the level of coordination in the allocation of capacity to transactions may not be enough under Zonal pricing, since intra-zonal transactions are, by default, allocated zero capacity why they should be allocated some. When zones are smaller, as under Hybrid zonal pricing, loop flows caused transaction internal to a zone are less likely. Then, coordination is more likely to be appropriate. Then, the grade for **Hybrid zonal pricing** is <u>High</u>, while that for coordination under **Zonal pricing** is <u>Moderate</u>.

Lastly, under **Average zonal pricing**, nodal prices and a nodal dispatch are calculated. This results in a very high level of coordination in transmission capacity allocation. Then, the coordination level under this scheme is <u>Very high</u> (appropriate). However, it must be taken into account that, in a pay-as-bid system like this, the system operator would extract the full consumer and producer surplus if bids are specified in accordance with own marginal production cost and marginal willingness to pay for electricity, even without congestion. Then, additional coordination needs to arise for determining the appropriate re-distribution of this surplus[2].

Market modelling imperfection costs

Some simplifications are always needed when building a network model starting from the full grid and all actual constraints. Therefore, the calculated optimal dispatch may result in infeasibilities for all the pricing methods discussed herein.

In **Nodal pricing**, a detailed representation of the grid is considered in the optimization problem where capacity allocation and prices are calculated. In theory, this results in an efficient allocation of capacity and prices that are consistent and simultaneously feasible when considering all grid constraints. Thus, the grade for nodal pricing is <u>Very good</u>.

The representation of the grid when computing the dispatch for a given set of bids is the same in **Average zonal pricing** as in nodal pricing. Then, not more infeasibilities should result from the former than under nodal pricing, which means that the grade for average zonal pricing according to this criterion is also <u>Very Good</u>.

In a **Single-node dispatch + re-dispatch** system the grid is disregarded at dispatch level. All bids in the full European system are lumped together to calculate a single European price, leaving all congestion management to less efficient redispatch procedures, which presumably will be less efficient than day-ahead scheduling for the handling of congestion. A single European pricing scheme should, thus, be rated as <u>Poor</u>.

Talking about **Zonal pricing schemes**, one should expect that the more detailed the network model considered is, i.e. the larger the number of zones considered is, the smaller infeasibilities resulting from implementing the market dispatch in the real grid will be. A hybrid zonal pricing system with fine granularity may be similar to a nodal pricing system. In contrast, lumping most of

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[2] However, as mentioned earlier, Average zonal pricing provides incentives for demand and supply to bid strategically to affect own prices, which could reduce significantly the net system surplus, and, therefore, coordination needs.

Europe into a few zones, as in zonal pricing with zones being coincident with countries, may be similar to applying a single node dispatch as far as the size of infeasibilities resulting from the market dispatch is concerned. Between these two extremes there are many zonal configurations. Therefore, hybrid zonal pricing is in principle superior to zonal pricing with respect to this criterion. The experience from Nordic countries indicates that there is a potential for many price-zones to be defined in large European countries. The grade of **Zonal pricing** is **Fair**, while that of **Hybrid zonal pricing** is **Good**.

In the following, we include a more detailed discussion of factors that influence to which degree (hybrid) zonal pricing can reflect congestion in the Internal Energy Market (IEM) in Europe.

Discussion in the context of Congestion Management solutions proposed within the IEM

The ability of zonal and hybrid zonal congestion management schemes to provide feasible solutions within the IEM largely depends on the representation made of network in terms of the following two factors:

a) Number and borders of bidding zones
b) Transmission capacity between zones

CACM [3] describes the development of a pan-European grid model that shall be considered when calculating transmission capacities between pairs of zones and allocating these to transactions. The optimization of the calculation of capacity and its allocation to transactions is set up for capacity calculating areas, which may include several TSOs. This process shall also somehow account for impacts on/from the rest of the European system. In the following paragraphs we discuss how elements of the capacity calculation and congestion management schemes considered in Europe affect the feasibility of the resulting energy dispatch. Two elements are considered as potentially affecting the feasibility of solutions computed:

- the capacity calculation and congestion management scheme applied, and
- generation and load shift keys (or distribution factors) considered.

Influence of the Capacity Calculation and Congestion Management Scheme

Two schemes are possible in this regard:

- In the coordinated Net Transmission Capacity (NTC) scheme, inter-zonal connection capacity to be used by transactions between each pair of zones is computed ex-ante before knowing bids submitted in the several areas of the system;
- In the Flow-Based (FB) methodology, requirements for use of the grid (bids submitted) by agents or transactions in all capacity calculation areas shall be considered jointly.

Coordinated NTC should be thought of as a minimum requirement for the intended integration of market operation in areas. Coordination of operation will be more efficient in FB solutions. However, both NTC and FB methods could render energy dispatch solutions that are compatible with overall inter-zonal capacities computed (total capacities on inter-zonal links). In order for this to be true, zonal capacities allocated to transactions among each pair of zones should be consistent with the capacity calculation and congestion management method applied. Not taking account of NTC for the use of transmission capacity by the rest of transactions when allocating capacity to those transactions between two zones involves that safety margins in the use of inter-zonal capacity must be much larger under this scheme than under FB allocation. This should render larger amounts of inter-zonal capacity unused under NTC, and therefore larger efficiency losses in this scheme would be required to achieve a feasible dispatch.

Influence of Generation and Load Distribution Factors

The size of infeasibilities resulting from the zonal dispatch may probably depend on our ability to represent real network constraints using the set of bidding zones defined. This is related to the number and borders of bidding zones considered, as well as on the limits set to the capacity to be allocated to transactions taking place among bidding zones defined.

Control (decision) variables in the congestion management problem do not only depend on the inter-zonal capacity calculation and allocation scheme implemented, but also on the predefined distribution factors representing how changes in power production or consumption by each agent, with respect to a defined forecast provided by system operators, affect inter-zonal flows. Generation and load distribution factors are computed so that they are the same for all nodes within a zone. This must be taken as a constraint in the optimization (congestion management) process. In other words, defining the zonal network model considered (specifically, number and borders of bidding areas), which is determining the size of infeasibilities resulting from the zonal dispatch, is implicitly equivalent to computing generation and load distribution factors. Generally speaking, the more accurately generation and load distribution represent the zones that relevant constraints limiting flows in the network divide the system into, the lower infeasibilities should be. Achieving infeasibilities of a small size when zones defined according to generation and load distribution factors are far from being accurate would involve reducing significantly the amount of capacity to be allocated to transactions, which would reduce significantly the economic efficiency of the dispatch.

Liquidity

Next, each of the design options considered are assessed against the criterion 'Liquidity', which has to do with the number of offers, or transactions, considered in the market for each price zone, and therefore the representativeness of prices computed.

Under **Nodal pricing**, the price of energy is separately computed for each node in the system, though values of prices for each node may depend on supply and demand conditions in other nodes. In the event of congestion limiting the amount of power imported into a node, or the amount of power exported from this node, the price applied in the node could largely depend on market bids by local generation and, more specifically, on local marginal generation. Then, prices may exhibit a high level of sensitivity with respect to bids by a lower number of agents. The market liquidity in these cases should be deemed low, certainly lower than under the rest of options. Then, the grade of Nodal pricing is Poor.

Under **Zonal pricing**, a single price is computed for each of the zones defined in the system, which, for congestion management purposes, are deemed free of internal congestion and losses. Losses, in any case, could be considered afterwards (zonal pricing scheme in the power exchange followed by a post-processing of zonal prices to reflect losses effects in each node).

Hence, all generation within each zone compete with external generators able to inject power into this zone to serve the local load. Marginal generators within those competing to supply the local load set the zonal price. This implies that, assuming zones are of a large enough size, the number of generators potentially influencing the price in each zone should be large enough to guarantee significant liquidity. Then, the grade of Zonal pricing is <u>High</u>.

Under **Hybrid-zonal pricing**, zones considered for the computation of prices are a subdivision of control areas. This constraint is not imposed under zonal pricing, and could potentially result in a larger number of areas under the former. Then, the liquidity level within each area could still be high but would, on average terms, be lower under Hybrid zonal pricing than under Zonal pricing. Then, the grade for Hybrid zonal pricing is <u>High-</u>.

Under a **Single node dispatch + re-dispatch**, all generation in the system would be jointly considered when determining which should be dispatched to supply load in the market. The set of generators dispatched in the market would not be conditioned by network constraints. Hence, all generators would be competing to be dispatched, and the marginal ones dispatched system-wide would set the market price. Only once the market price has been computed, would network constraints be considered to determine changes to be made to the original dispatch. However, these changes, also known as redispatch, would not affect market prices, but only the price earned by constrained-off and on generators. Hence, the level of liquidity achieved under this scheme would be the highest at system level. Liquidity at local level in the redispatch process could be very low if binding network constraints do not allow competition among generators from large enough areas to take place. However, if market power (MP) problems exist in the redispatch process following the computation of the single node dispatch, the same problems would arise under nodal and zonal pricing schemes already in the original dispatch, which would allow agents having local MP to affect prices applied to a larger number of power plants than in the redispatch process. Hence, incentives to exercise this market power would be larger under Zonal and Nodal pricing schemes. Thus, the grade of the option Single node dispatch + redispatch is <u>Very high</u>.

Now, we assess the case of the **Average zonal pricing** scheme. In this case, prices applied on demand would result from averaging prices offered by generators that are dispatched within each area. Generators dispatched, which would be selected taking into account all network constraints, would earn a price corresponding to their bid, i.e. they would be paid as bid. This involves that the price applied on demand would depend on all accepted bids considered jointly. On the other hand, the price earned by each generator would solely depend on its bid as long as this is competitive. This creates incentives for generators not to bid their variable costs but the maximum price that is compatible with their being dispatched. Then, generators need to predict congestion in the system and bid accordingly. If not predicting accurately congestion, generators risk being left out of the dispatch. Gaming incentives provided to generators under this scheme may probably result in the price in each zone to be applied to demand being less reliable (predictable) than the one under zonal pricing. At the same time, prices earned by generation individually would probably be largely unreliable. The latter would probably be even less reliable than under a nodal pricing approach, since generation prices would directly depend on their capacity to accurately predict market and system conditions. Then, under Average zonal pricing, the liquidity of relevant markets for the computation of **demand prices** is deemed **Fair**, while that of markets considered for the computation of **generation prices** is **Poor**.

2.3.2 Robustness

Under this criterion we are assessing whether changing system conditions may impact the efficiency of price signals applied under each scheme.

Nodal pricing can be deemed to always produce efficient prices unless there is not enough market liquidity within each of the different zones that congestion divides the system into. However, this effect of liquidity on the level of competition in the energy dispatch is assessed under the liquidity criterion. Provided an adequate level of competition exists, prices computed under nodal pricing should always be efficient regardless of existing system conditions. Then, the grade of Nodal pricing is **Very high**.

Under **Zonal pricing**, prices computed may not be efficient if congestion zones are not updated when relevant system conditions change, or if these zones are not defined according to network bottlenecks. The need to update zones renders the scheme less robust than nodal pricing. One must take into account that updating price zones may require a change in TSOs' control areas. Then, the grade of Zonal pricing is **Fair**.

The validity of any specific set of zones under **Hybrid zonal pricing** is similar to that of zones under pure Zonal pricing. However, the fact that price zones defined under Hybrid zonal pricing are a subdivision of administrative zones (control areas or countries) results in a situation where these price-zones can be smoothly changed if necessary (for instance, not causing the redefinition of control areas). Then, the robustness of this scheme is higher than that of non-conditioned Zonal pricing, but lower than that of Nodal pricing, since any set of price zones may not be valid after a change in system conditions if changes to them are not undertaken. The grade of Hybrid zonal pricing is, thus, **High**.

The efficiency of the **Single node dispatch + redispatch** method critically depends on the level of congestion in the grid and, to some smaller extent, on the level of transmission losses as well. This is so because, the larger the level of congestion and losses is, the larger the changes that need to be made to the original unconstrained dispatch in order to make it feasible will be, and the further this original dispatch is from the optimal economic one. Then, the price computed in the unconstrained dispatch is further from efficient locational marginal prices the larger congestion and losses in the system are. The larger differences are between optimal prices and the system price applied, the larger efficiency losses resulting from the sub-optimality of price signals can be. Notice that price signals may affect both the operation of generation and demand facilities and sitting decisions for these facilities. Hence, changes in system conditions affecting the level of congestion and/or losses in the grid may probably have an impact on the efficiency of the solution provided under the Single node dispatch + re-dispatch scheme. Besides, contrary to what occurs under zonal pricing schemes, there is no way to adapt the single node dispatch (like changing zones under a zonal dispatch) to make prices resulting from it more efficient. Thus, the grade of the Single node dispatch + re-dispatch option is **Fair-**.

Similarly to zonal schemes, prices applied to demand under the **Average zonal pricing** scheme are zonal, and their efficiency, depend on how closely zones defined reflect congestion in the system and losses. Hence, changes in the pattern of congestion and losses in the system can affect the efficiency of zones considered for the computation of demand prices. However, producer prices and their dispatch is set according to nodal prices (since producers, in order to maximize profits, shall aim to offer the nodal price for their location), which are quite robust. Hence, this method has a relatively high level of robustness when compared with most other methods. Thus, the grade of this scheme is <u>Fair+</u>.

2.3.3 Implementability

Computational feasibility

This criterion concerns the computational burden imposed by each of the network representation methods considered when solving the energy dispatch problem.

Computationally speaking, the representation of the system network under **Nodal pricing** is very demanding, since it involves explicitly considering all network constraints and all physical nodes. Thus, a powerful computer would be needed to compute the energy dispatch and prices in a large system like the European one. If applied in very large systems where a multiplicity of bids of different formats is considered (some of them being complex), the problem to solve could potentially become challenging from a computational point of view. Besides, data requirements to apply this pricing scheme are also very high. Thus, the grade of Nodal pricing is <u>Fair</u>.

Zonal pricing schemes consider only zones instead of nodes in the dispatch and only constraints affecting power exchanges among these zones. Then, their computational feasibility may depend on the specific system considered and the number of zones that need to be defined in it, but should in any case not be very large. Data requirements would be lower than under a nodal pricing scheme. The grade for Zonal pricing is <u>High</u>.

Hybrid zonal pricing has, similarly to Zonal pricing, a level of computational burden that should be affordable. Due to the additional constraint that zones are a subdivision of administrative ones, the number of zones defined may be higher than under Zonal pricing. This would render the computational affordability of this method high, but a bit lower than that of Zonal pricing. Data requirements would be similar to those under a zonal pricing scheme (a bit larger). The grade of Hybrid zonal pricing is <u>High-</u>.

Single node dispatch + re-dispatch is, probably, the option that simplifies the dispatch problem to the largest extent and, therefore, the one that results in a problem that is the easiest to solve. No network constraint is considered initially and, afterwards, changes made to the original dispatch are only those needed to make it feasible. Thus, network constraints considered may be only those that are violated initially. Many different implementations of this scheme are possible, in any case. Data requirements would be lowest under this scheme. The grade for this option <u>Very high</u>.

The computational burden of **Average zonal pricing** is largely as high as that of nodal pricing, since it entails the computation of nodal prices in all nodes in a first stage of its implementation. A full, network-constrained, economic dispatch is computed. Prices applied to load and generation are not the marginal ones in each node. However, prices applied to most demand are zonal average ones computed from nodal ones. This involves that, practically speaking, nodal prices must be computed for a large part of the nodes in the system. This may probably not represent a relevant simplification of the problem to solve. Thus, the grade of this method is Fair, as for Nodal pricing.

Compatibility with existing regulation in Europe

This concerns whether the energy dispatch and energy pricing principles applied are in line with principles and regulation applied not only at European level but also at national level.

Nodal pricing may result in geographically differentiated prices to be applied to both demand and generation. This may enter into conflict with the established principle in many EU countries that consumers in general, and domestic ones in particular, should not be paying prices that depend on their location within the country. The rationale behind this well established principle is that agents bearing a risk should be those that are best prepared to manage it. Then, given that domestic consumers cannot properly control where they are located (since this is a decision that is largely conditioned by many aspects with implications that exceed their electricity consumption) these consumers should not be held responsible for the electricity supply costs that are specific to their location. Besides, some countries have traditionally applied regulation favoring certain types of generation. Then, having lower prices earned by this generation than those earned by other types, as potentially resulting from the application of price-differentiation mechanisms like Nodal pricing, could be against principles related to local policy, like industrial policy ones. Thus, the grade of Nodal pricing is Poor.

The **Zonal pricing** scheme may largely incur in the same kind of incompatibilities with established pricing principles as the Nodal pricing one. After all, both schemes could result in locationally differentiated energy prices applied to generation and demand within each country. However, under Zonal pricing, authorities normally have defined zones according to other principles than purely techno-economic ones, like socio-political ones, thus trying to, at least, partially avoid discrimination among agents that is perceived as unfair, or being against the strategic interests of each country. Thus, for most countries, zones have been made to coincide with countries, which is politically acceptable. Then, the zonal pricing approach is applied in such a way that it largely avoids incompatibilities with currently existing, and broadly accepted, pricing principles. In any case, price discrimination among consumers within each country would be inevitable unless zones are made coincident with countries, which would probably be highly inefficient. The grade of this scheme is Fair.

Under **Hybrid zonal pricing**, the number of price zones within each country would be at least the same as under a zonal pricing scheme, resulting in locationally differentiated prices. If more than one bidding zone is defined within countries, this scheme may be in contradiction with pricing principles commonly accepted in part of the European countries. On the other hand, there are already some countries where market splitting is applied. Thus, Hybrid zonal pricing may be deemed acceptable or not depending on the country considered. To summarize, incompatibilities with pricing principles can be deemed comparable to those under the zonal pricing scheme, though larger on average terms. Thus, the grade of this option is Fair-.

Under a **Single node dispatch + re-dispatch** approach, a single price is computed for all the European system. This scheme is not in line with current practice in Europe today, nor with the TM as represented in CACM. Besides, if this scheme is applied, large efficiency losses would result, since significant congestion could affect the trade of power within certain countries. The grade of this option must be **Poor**.

The **Average zonal pricing** scheme involves applying prices that are specific to each generator in the system (pay-as-bid remuneration of generators, that may end-up resembling nodal pricing) plus the computation of zonal prices paid by consumers. This could contradict non-discrimination principles referring to both demand and generation. Prices applied to non-flexible consumers would only be politically acceptable if the defined zones coincide with countries. However, the two-price system affecting consumers discriminates them according to whether they are flexible or not. National and European authorities may conclude that this mechanism is introducing unfair discrimination among consumers. Discrimination among generators would be inevitable, since, taking into account all constraints in the energy dispatch, generators would be encouraged to bid, and therefore earn, their corresponding nodal prices. Besides, pay-as-bid regulation would contradict marginal pricing principles, though these are not universally adopted in Europe, even in the day-ahead time frame. The grade of this option is **Poor+**.

Simplicity (Conceptual one)

The simpler the functioning of a market is to understand, the more predictable its output will be, and, therefore, the easier its acceptance by parties will be.

Understanding the outcome of the application of a **Nodal pricing** scheme is not easy many times. Both the dispatch of units and prices applied result from a complex process where a multiplicity of constraints of many different kinds may be taken into account. Then, the result may be contested. Thus, the grade of Nodal pricing is **Poor**.

Both the dispatch and the prices applied as resulting from a **Zonal pricing** scheme are easier to understand that those produced under Nodal pricing, even though there may be subsequent changes to be made to the zonal dispatch due to the need to make it feasible. These changes may be obscure from an agent's perspective. Thus, the complexity of this scheme may be deemed of a medium level. The grade for Zonal pricing is **Fair+**.

The complexity of a **Hybrid zonal pricing** scheme can be considered similar to that of a pure Zonal pricing scheme, even when some more zones may exist. Its grade is **Fair**.

The outcome of the **Single node dispatch + re-dispatch** and the system price resulting from it are very easy to understand, though some relevant changes to it (depending on the level of congestion in the grid) may be necessary to make the dispatch feasible. Changes to be made to the dispatch could depend on a multiplicity of features that are far less predictable. In any case, this scheme should be considered the easiest to understand. The grade for Single node dispatch + redispatch is **High**.

The energy dispatch resulting from the **Average zonal pricing** scheme is difficult to understand and predict, since all kinds of constraints are considered in it. Rules to determine prices provide agents with incentives not to offer energy at production costs or, in the case of consumers, bid the value that energy has for them. Then, electricity prices resulting from this scheme are difficult to predict. Besides, paradoxically rejected offers by generators could exist, i.e. some offers by generation may be rejected even when offers by other generators at a higher price in the same area, or even node, are accepted. Then, results may be deemed difficult to understand in general terms. The grade of this option is Poor.

Implementation costs

Costs of implementing a **Nodal pricing** model may generally be higher than those of implementing a zonal one, since, for example, software used may need to change and the amount of information exchanged will increase substantially in the former case. The communication infrastructure and scheme, as well as the control one in some cases, may significantly change as a result of the application of a nodal scheme. Then, the implementation costs of this scheme will be very substantial. The grade for Nodal pricing is Poor.

Implementing a **Zonal pricing** scheme where zones do not coincide with currently existing ones may require the change of the footprint of local power exchanges or aggregators, and the structure of the communication and control scheme adopted. This will probably result in relevant implementation costs, though probably lower than those of a nodal scheme. An exception, which would result in almost no implementation costs, is the zonal scheme whereby new zones coincide with countries, since this is the scheme already existing in Europe. The grade for Zonal pricing is Fair-.

The implementation costs of a **Hybrid zonal pricing** scheme may be similar to those of a pure zonal one. On the one hand, the number of zones will probably be larger than those in the zonal scheme. On the other, old control and market zones could still play a role under the Hybrid zonal scheme, since new zones may be reporting to these (new zones are built to be a subdivision of old ones). The grade of Hybrid zonal pricing is thus Fair-.

The implementation costs of the **Single node dispatch + re-dispatch** scheme are low compared to other options except for a zonal scheme where zones coincide with countries. Implementing a single node dispatch would involve that each country provides data to a single, global, European control and dispatch center. This dispatch center should be created and given control of market operation at European level, which is challenging because it may face the opposition of national system and already existing market operators. The grade of this option is Fair+.

Lastly, implementing an **Average zonal pricing** scheme would involve large costs, similarly to what occurs with a nodal scheme. This is due to the fact that all constraints would need to be considered in the market dispatch, contrary to what occurs currently in most European systems, and a separate price would be computed for each generator in the system, potentially. The amount of market information exchanged concerning consumers would be similar to the current one, though zones considered for consumer pricing could change as well. The performance of this option is Poor.

Experience with its implementation

Authorities and systems tend to rely more easily on schemes that have been widely applied.

Nodal pricing has not been applied so far within the IEM of the EU. However, it has been applied in several other regions throughout the world, including, several Regional Transmission Organization (RTO) regions within the USA, the Central America regional electricity market; and some regional markets in Australia. Thus, some relevant experience exists about its implementation, which has allowed authorities to identify advantages and drawbacks of its implementation not only on the paper, but also in practical terms. The grade of this scheme is High.

Zonal pricing is a mechanism applied in a large amount of systems throughout the world. These include the IEM of the EU, where zones coincide with countries largely, or the Brazilian system in America. It was also applied for some time in some regional markets in the USA, like Electric Reliability Council of Texas (ERCOT). Thus, significant experience exists about the application of this scheme. The grade for Zonal pricing is High.

The **Hybrid zonal pricing** scheme, a variant of the zonal pricing one, can be deemed to be applied within Nordic countries, and Italy, since several price zones are defined within each country in both of these regions. Authors are not aware of its application in any other system. However, experience gathered on the application of Zonal pricing, being this method similar to Hybrid zonal pricing, may be of some help as well when applying the latter. Then, the grade of this option is High-.

The **Single node dispatch + re-dispatch** option is, by far, the scheme that has been more widely applied in the world. It has been applied within most national systems in Europe. It has also been applied in South America, and many other parts of the world, including a vast majority of traditionally regulated systems, when looking at the functioning of these systems from a local perspective. Thus, experience about its implementation at national level is very large. However, experience about the implementation of a Single node dispatch in regions comprising several systems or control areas is limited, since congestion normally occurring at regional level advices implementing a congestion management and pricing scheme with a finer level of granularity. The grade of this option is High.

Figure 1 below illustrates the fact that the Single node dispatch + re-dispatch and Zonal pricing schemes are simultaneously applied in the CWE region of the IEM of the EU, each mechanism at a certain level of network representation.

No instance has been found of the application of the **Average zonal pricing** scheme. However, a scheme similar to Average zonal pricing has been applied in some systems like Brazil. According to the latter scheme, a nodal energy dispatch (full, network-constrained, economic dispatch) is combined with zonal pricing computed considering a set of predefined zones. However, non-negligible differences exist between the results produced by both schemes. Zonal prices applied in Brazil, instead of resulting from averaging nodal ones within each zone, and being applied only to demand, correspond to marginal supply costs computed considering only inter-zonal constraints. Therefore, experience gathered with the use of the latter scheme cannot be of use in understanding consequences from the application of Average zonal pricing. Overall, the performance of the scheme assessed here is Poor.

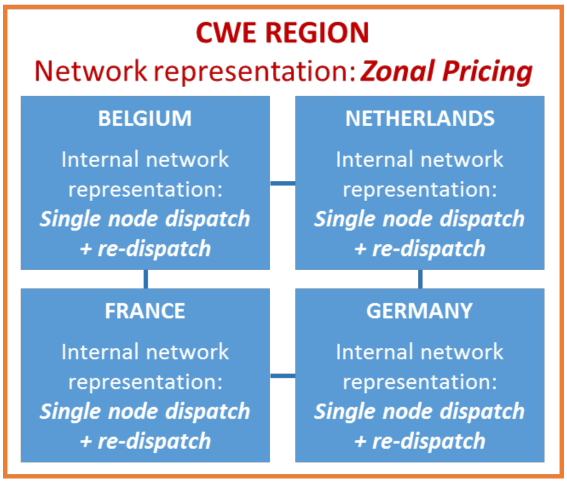

Figure 1: Hierarchy of Network representation schemes in the energy dispatch within the CWE region in Europe

Possible extension to several timeframes (scalability, replicability)

If possible, the system of prices devised (level of price differentiation by location) should be implementable not only in day-ahead markets, but also in those markets organized in other time frames (intraday, balancing energy, etc.). If network constraints limit the exchange of power among areas of the system in the day-ahead time frame, this may also happen in other time frames as well as in balancing markets. Thus, in order for the scheme to be coherent with that in other time frames and markets, the representation of the grid should be coherent.

A scheme of **Nodal prices** can be also considered for the long term allocation of capacity, as well as that in intraday and real-time markets (as it happens in some parts of Australia or PJM), and even balancing ones. Implementing Nodal pricing in close-to-real-time markets in large systems may be challenging though, even when experience exists about this. In any case, somehow, network constraints must be taken into account in changes made to the energy dispatch in the very short term. The grade of Nodal pricing is High-.

There is also experience about the application of **Zonal pricing** schemes in very short term markets and balancing ones. This is currently the case in many European markets, where a separate price of energy is applied in each country in the day-ahead, as well as in the long term (transmission rights sold according to the difference among zonal system prices), and separate prices of balancing services are applied in each country. Then, implementing Zonal pricing in the day-ahead stage should not be incompatible with having a coherent set of markets in place for the different time frames and products. The grade of Zonal pricing is High.

The implementation of a **Hybrid zonal pricing** scheme is possible also in several time frames and markets, since, conceptually speaking, it does not differ substantially from a Zonal pricing scheme. The grade of Hybrid zonal pricing is High.

Implementing the **Single node dispatch + re-dispatch** scheme at European level would be theoretically possible in any time- frame or for almost any market. However, this scheme is not easily applicable in shorter time frames than the day-ahead. Thus, for example, implementing it in real time would involve the need to make large changes to the resulting dispatch, with barely no time available for this. In other words, this network scheme is not applicable to real-time markets because the dispatch resulting from the former must be feasible, or very close to be feasible. Thus, the suitability of these network model to be extended to other time frames than the day-ahead must be considered low. The performance of this option is Poor.

Lastly, the **Average zonal pricing** scheme would, in principle, be implementable in any timeframe, since the resulting dispatch would be feasible, which is quite relevant in very-short term markets like energy or balancing energy ones. However, average zonal prices should not be applied to service providers (sellers in the market), since average zonal prices may not be high enough to cover the bids of some of those service providers that are dispatched. Only buyers, i.e. users of these products, should be paying average prices. The performance of this scheme with respect to its replicability is High.

2.3.4 Fairness

Distributive effects

It may be considered fair that generators earn the same price than the one paid by consumers, and that the different agents amongst the group of generators, and of consumers as well, are subject to the same prices. This involves having a same price for them all.

Under **Nodal pricing**, the price at each node corresponds (by construction) to the intersection of the bid and offer curves that are built leaving aside those offers (resp. bids) that cannot marginally supply demand in this node (resp. be marginally supplied from this node) because of binding network constraints. Consequently, prices at each node may be different, leading to discrimination among agents both from the same group and from different groups. Therefore, this scheme performs Poorly according to its distributive effects.

Under **Zonal pricing**, the same price is applied to all consumers and generators in each zone. There may however be differences in prices among different zones. Therefore, Zonal pricing performs Fairly according to its distributive effects.

The same assessment is valid for **Hybrid zonal pricing** and Zonal pricing. However, zones under the former are smaller and may lead to larger aggregate differences in prices, at least among generators. Therefore, the grade of Hybrid Zonal pricing is Fair-.

Under a **Single node dispatch + re-dispatch**, the same price is applied to all consumers and generators. Therefore, this scheme performs Very well according to its distributive effects. However, the re-dispatching after the single node dispatch impacts the distribution of social welfare, and therefore price differences, according to the remuneration set for generators and how modelling imperfection costs are passed-through to network users.

Under **Average zonal pricing**, consumers within the same zone pay the same price for electricity. Therefore, from the **consumers' point of view**, this option performs Fairly, as Zonal pricing does. By contrast, generators earn different prices depending on the node where they are located. In addition, even at the same node different prices may be earned by different generators, since pay-as-bid is in place. However, prices offered by generators in the same node may converge to a single one, since they have incentives to behave strategically. Therefore, from the **generators' point of view**, this option can be assessed as Poor (like option Nodal pricing).

Compatibility with the application of single price to small consumers within a region, or country

It is considered fair that all small consumers pay the same price for electricity supply. Indeed, electricity is manytimes considered a universal and public service which price shall be the same for all small consumers within each country. This is for example the case in France, where regulated supply tariffs are equalized at national level ("péréquation tarifaire").

Provided that retail market prices reflect wholesale market ones, consumers located at different nodes of the network may pay different prices under **Nodal pricing**, which may be perceived as unfair. Therefore, the compatibility of this option with the application of a single price to small consumers can be considered as Poor.

Provided there is not more than one price zone per country, and the retail market prices reflect the wholesale market ones, all consumers within a given country pay the same price for the supply of electricity under **Zonal pricing**. Therefore, the compatibility of this option with the application of a single price to small consumers can be deemed Fair.

For **Hybrid zonal pricing** the assessment is related to that for Zonal pricing. However, given that zones defined in the former tend to be smaller, price discrimination among consumers is larger in this scheme. Then, the compatibility of this option with the application of single price to small consumers is deemed Fair-.

Under a **Single node dispatch + re-dispatch** scheme applied in Europe, the price of electricity on the wholesale market would be the same in all countries. Then, provided retail prices reflect wholesale ones, all European citizens would pay the same price for electricity consumed. The performance of this option can be deemed Very good for the criterion here assessed.

Under **Average zonal pricing**, prices of non-flexible consumers (most) would be the same within each zone, but there would be some differences among zones. Therefore, the compatibility of this option with the application of a single price to small consumers can be deemed Fair.

Transparency

A scheme is considered transparent if everybody can understand it and if its output can easily be predicted, also by agents with no detailed information about the system (grid constraints, offers and bids from other agents…) and those with limited computing power.

Nodal pricing is a complex scheme where prices depend on many constraints. Thus, prices resulting from this scheme cannot be reasonably predicted many times – except by agents having access to very detailed knowledge about the grid, offers and bids, and having large computing power. Transparency for this option can therefore be assessed as Poor.

Under **Zonal pricing**, the process followed to calculate prices within each zone is transparent, while the way zones are defined may not be very transparent. Transparency under this option can therefore be considered Fair.

For **Hybrid zonal pricing**, the same assessment can be made as for Zonal pricing. Transparency under this option can be considered as relatively Fair.

When a **Single node dispatch + re-dispatch** is computed, the system price is transparently computed and easy to predict, since results from the intersection of system-wise bid and offer curves. Transparency for this option can therefore be considered **Very good**. However, the way re-dispatching actions are carried out and the corresponding costs are distributed, may not be very transparent.

Lastly, under **Average zonal pricing**, the method employed to compute prices is more complex than under Zonal, or Hybrid zonal, pricing. Prices are more difficult to predict and rules are more difficult to understand in the former. Then, the level of transparency of this option is lower than that of Zonal pricing, and similar to that of Nodal pricing. The method here assessed may be slightly more transparent for generator prices, but less for consumer ones. Transparency under this option can therefore be deemed as Poor.

2.4 Conclusions

In the previous section, options for the representation of the network in short term markets have been assessed according to their impact on the short and long term functioning of the system.

Table 1 presents a summary of the assessment of Network representation options according to the four families of criteria considered: Efficiency, Robustness, Implementability, and Fairness. Very weak and weak grades are highlighted in red and light orange, while very good and good grades are highlighted in green and light green.

It can be concluded that:

- Nodal pricing, Single node dispatch + re-dispatch and Average zonal pricing have some serious drawbacks, or do not perform well on average terms, and should be discarded as sound options to implement.
- Network representation options preliminarily retained as interesting are Hybrid zonal pricing and Zonal pricing.

Complementing Table 1, Figure 2 provides the main arguments considered to classify design options explored into promising ones (Hybrid zonal pricing and Zonal pricing) and those others to be discarded. Arguments are provided in the form of strong and weak points of each of the two groups of design options defined.

Table 1: *Summary of the assessment of Network representation options according to the four families of criteria*

		Nodal pricing	Zonal pricing	Hybrid zonal pricing	Single node dispatch + redispatch	Average zonal pricing
Efficiency	*Marginal cost reflectivity*	Very good	Fair	Good	Poor	Fair
	Level of coordination	Very high	Moderate	High	Poor	Very high
	Market modelling imperfection costs	Very good	Good	Fair	Poor	Very good
	Liquidity	Poor	High	High-	Very high	Fair (demand) Poor (generation)
Robustness		Very high	Fair	High	Fair-	Fair+
Implementatbility	*Computational feasibility*	Fair	High	High-	Very high	Fair
	Compatibility with existing regulation	Poor	Fair	Fair-	Poor	Poor+
	Simplicity	Poor	Fair+	Fair	High	Poor
	Implementation costs	Poor	Fair-	Fair-	Fair+	Poor
	Experience with implementation	High	High	High-	High	Poor
	Extension to other timeframes	High-	High	High-	Poor	High
Fairness	*Distributive effects*	Poor	Fair	Fair-	Very good	Fair
	Single price to small consumers	Poor	Fair	Fair-	Very good	Fair
	Transparency	Poor	Fair	Fair	Very good	Poor

Design Options	Weak points (-)	Strong points (+)
✓ Hybrid Zonal Pricing ✓ Zonal Pricing	• Low compatibility with existing regulation (price discrimination) • Not fair (price discrimination) • **Zonal Pricing**: MC Reflectivity in meshed grids, Market Modeling Imperfection Costs in Meshed Grids	• High Liquidity • Easy to compute dispatch • Possible extension to other time frames • **Hybrid Zonal Pricing**: High Local Marginal Cost Reflectivity, Large Robustness • **Zonal Pricing**: Large experience with its utilization
✓ Nodal Pricing ✓ Average Zonal Pricing ✓ Single Node Dispatch	• **Single Node Dispatch**: MC Reflectivity, Market Modeling Imperfection Costs, Robustness, Compatibility with Regulation, Extension to several time frames • **Nodal pricing, Average Zonal Pricing**: Liquidity, Level of coordination required, Lack of compatibility with regulation, complexity, Implem. costs, Lack of Fairness and experience (Av. Zonal)	• **Nodal Pricing and Average Zonal Pricing**: Modeling Imperfection Costs • **Nodal Pricing**: MC Reflectivity, Robustness • **Single Node Dispatch**: Liquidity, Simplicity, Computational Feasibility, Level of Coordination Required, Experience with its Utilization, Transparency, and No Price Discrimination

Most promising design options (overall strong grades) Discarded design options (overall weak grades)

Figure 2: Classification of Network representation options into weak and strong ones from the point of view of their impact on the short and long term functioning of the system, and arguments considered for this

3 Timing of short term markets

The design elements corresponding to the timing of markets include time parameters defining (i) the energy markets (run by Power Exchanges - PXs), (ii) the reserve markets (run by System Operators -SOs) and the timing of the frontier between energy market and reserve use, i.e. (iii) the gate closure.

There are a large number of parameters characterizing the timing of electricity markets. The most relevant ones have been schematically represented in Figure 3for the energy market (for the reserve markets are analogous).

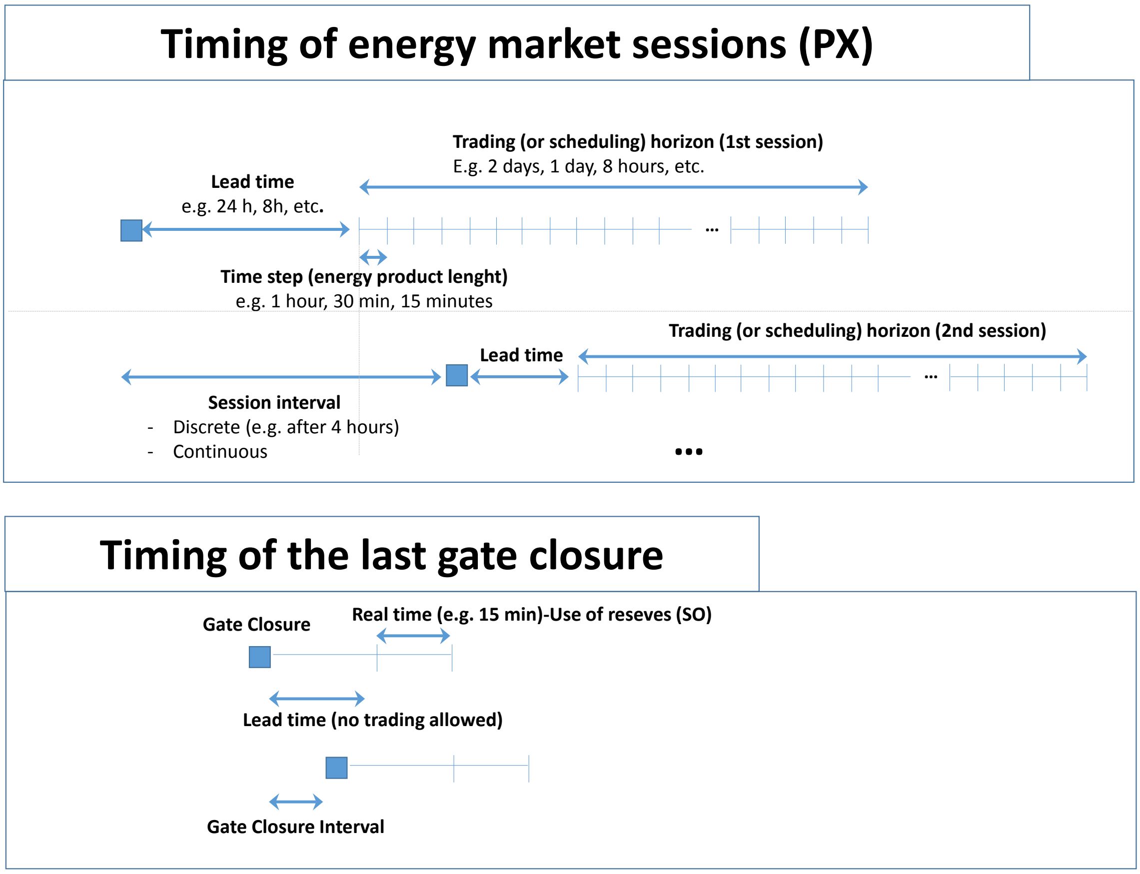

Figure 3: Representation of the design of the sequence of markets and main parameters affecting it

The combination of different values of the parameters above can lead to multiple designs. The following are just some basic examples of the major options available:

- Concentrate liquidity in a single session (financially binding). Immediately after the session comes the gate closure (no further trading is allowed, and any change in the program will be considered as imbalance). This single session could be the Day-Ahead Market (DAM) or could alternatively be closer to the Real-Time Market.
- Concentrate liquidity in a first opening session (typically a Day-Ahead Market, although it could be set closer to the real time) and complementing it with discrete sessions of

shorter-term ones until the gate closure is reached. This corresponds to the design in Spain and Italy (it includes a cross-border intraday market that will allocate implicitly the capacities available on the borders). The proposed design option should evaluate the trade-off between concentrating the liquidity (i.e. fewer sessions), or facilitate trading of market novation as it happens (i.e. more sessions). Reserves could be acquired after each energy auction is cleared.

- Concentrate liquidity in a first opening session (e.g. Day-Ahead Market) and completing it with continuous shorter-term trading to accommodate any change in the programs. This corresponds to the European target model design and is implemented in Northern and Central-West Europe. The proposed design option should evaluate whether there is enough liquidity in the continuous market. Reserves could be procured at any time based on TSO information and updates.
- There is no opening session, with the market for energy (and reserves) being continuous.

This subtask focuses on the timing of the first market (currently the DAM), the timing of intraday market, the timing of the (last) gate closure before real-time and the timing of the reserve markets. The following sections deal respectively with these designs.

3.1 Options for main design elements related to the timing of markets

3.1.1 Timing of the first market (currently DAM)

Presently, in the context of the Price Coupling of Regions, the timing of three processes concentrate most discussions: pre-coupling, coupling and post-coupling.

Pre-coupling involves the following sub-processes:

- Nomination of long-term (LT) rights – where applicable (Market Players)
- Calculation of DA capacities (TSOs)
- Prediction of market conditions - external factors e.g. weather, demand, generation output etc. (Market Players)
- Creation and submission of bids - internal strategy (Market Players)

Coupling tasks include:

- closing order book,
- anonymizing orders,
- sending orders to central calculation engine,
- market coupling calculation,
- broadcast of results,
- verification of results by PXs and TSOs,
- portfolio allocation and
- publication of results.

Post-coupling:

According to current ENTSO-E standards, TSOs activities e.g. to guarantee security of supply (running stability checks and N-1 tests, checking for line rating margins, etc.) and calculate intraday (ID) capacities must start at 3.30 CET. The 3:30 deadline is set by ENTSO-E, and could potentially be changed (requires an in-depth cost-benefit analysis).

There needs to be headroom to secure price formation and capacity allocation in case of market or operation incidents. This includes:

- Possibility to re-open the order book for second auctions in case of abnormal prices
- Allowance for technical intervention in case of operational incidents.
- Allowance for partial-coupling or full decoupling processes in case of technical failure
- Alternative capacity allocation e.g. shadow (explicit) auctions

3.1.2 Timing of intraday markets

Three major alternatives exist as regards when to schedule intraday markets:

- Continuous trading: in continuous trading bids can be submitted and matched by PX at any time before gate closure time.
- Intraday discrete auctions: auctions are called at specific predefined time.
- Hybrid: a hybrid design is based on continuous trading, but also includes the possibility of complementing the design with discrete auctions to ensure market liquidity. These discrete auctions can be called at specific predefine time, or conversely can be call based on the occurrence of some events.

3.1.3 Timing of reserve markets

In parallel to the timing of the “energy” product, it has to be also determined the timing of the ancillary services products. If co-optimization (energy-ancillary services) is to be considered, the timing of the ancillary services products is linked with that of the energy product. Here the alternatives are:

- Long-term procurement of reserves
- Short-term procurement of reserves
- Day-ahead
- Day-ahead plus intraday updates
- Hybrid procurement
- Reserves are acquired under different schemes with different timing (e.g. regulatory requirements satisfied on year/month/week-ahead; free bids complement the reserve pool on a day-ahead or intraday timeframe)

3.1.4 Timing of the gate closure

Where to situate the gate closure has always been considered as one of the most controversial design decisions. This is clearly explained by (Stoft, 2002) when saying that: *“between the real time and the longer term there are dividing lines that describe the system operator’s diminishing* *role in forward markets. Where to draw those lines is the central controversy of power-market design"*.

Each system has traditionally used different criteria to define the point at which the SO takes increasing control of the system so as to ensure security. Today, the gate closure situates around 1 hour before real time. RES-E adds to the discussions on where to draw this frontier. The two major approaches are:

- Bringing it closer to the real time: allows a more efficient participation of RES-E given the improvement of forecast accuracy at shorter times and closer to delivery.
- Keeping it around one hour before real time, or even moving it away from real time: sometimes claimed to give more capability to the SO to ensure security of supply while also giving further incentives (beyond market signals) to improve forecasting tools.

Even if those advantages are true, the disadvantages of a gate closure far away from real time will overcome that possible advantages. Gate closure should never be far away from real time.

3.1.5 Other design elements out of the scope of this study

Other relevant design elements related to the timing of markets, but considered to fall out of the scope of the project:

- Time horizon for bilateral transactions (when agents have to nominate to the System Operator the bilateral contracts): In this respect, in some systems, bilateral contracts cannot be nominated after the day-ahead market (e.g. Spain).
- The length of the products (e.g. in the day-ahead market currently one hour).
- Timing of the corrective measures adopted by the SO to ensure feasibility and reliability. For example, there can be a corrective dispatch after each session at predefined periods or conversely the SO may call corrective dispatches on a continuous basis (if necessary). Similarly, actions to ensure the system balance may be preventive (i.e. called before real-time, in prevision of imbalances) or only curative (i.e. called only in real-time as the system is observed to be imbalanced)

3.2 Assessment criteria

3.2.1 Efficiency

Efficiency of price signals and dispatches

With the development of RES-E, the intraday markets become increasingly important. The timing of markets must allow providing efficient price signals and efficient dispatches, while allowing the System Operator ensuring a secure operation.

The proper timing of markets may constitute a part of the answer to the flexibility challenge. In order to maximize efficiency the design should be tested against the market capability to:

- maximize the value of existing flexible resources
- maximize the value of existing non-flexible resources

- minimize the impact of uncertainty, that is, allow for coping with non predictable changes related to non-dispatchable generation and load
- minimize the need for flexible resources.

Market modelling imperfection costs

The lack of co-optimization of energy and reserve products is known to increase costs. The effect of the lack of co-optimization can however be softened if enough liquid markets are in place.

Liquidity

In general, the shorter and more frequent the timeframes the more beneficial for all generators if enough liquidity is ensured. When defining the timing of the different markets it is essential to evaluate the resulting liquidity and the derived effects. This is probably the major concern as regards the design of the timing of short-term markets.

Ensuring the availability of a complete set of time frames to trade the products is essential for the functioning of the whole scheme.

3.2.2 Implementability

Implementability involves compatibility of the design alternatives with the Capacity Allocation and Congestion Management and the Balancing Network Codes, the simplicity of the market sequence, the implementation costs and also the experience with the implementation of a market in other systems.

3.3 Assessment of options for the design of the sequence of markets

3.3.1 Day-Ahead

Efficiency

In general, to maximize efficiency and avoid distortion, all the abovementioned tasks involved by the pre-coupling should be pushed to take place as late as possible.

Regarding the coupling process, the efficiency is increased as the total time needed to conduct the associated tasks is shortened. However, coupling needs to be conducted in a robust and secure manner. Total time to conduct the tasks, under nominal operational conditions, currently takes 42 minutes.

3.3.2 Intraday

Efficiency

Discrete auctions

Discrete auctions provide lower flexibility since market events can only be captured at the subsequent auction. Therefore, from a flexibility point of view, one would tend to prefer more frequent auctions. On the other hand, discrete auctions provide higher liquidity if they are not too frequent since they concentrate transactions reflecting all the events since the last session (that said, there are also academic studies that show the opposite[3]). Consequently, the frequency (and timing) of discrete auctions needs to be carefully chosen to take into account these two antagonist effects.

Another fundamental difference between continuous trading and auctions resides in the way orders are submitted and matched. In continuous markets, bids are cleared at the price of submission (i.e. pay as bid), while in auctions, all bids for the same products are cleared at the same prices (i.e. pay as cleared). The consequence is that in auctions, traders are incentivized to submit orders at their own marginal costs, while in continuous markets, traders have to estimate the system marginal cost.

Also, auction systems typically enable a better cross-matching of different products (e.g. matching a block of 4 hours with 4 hourly orders, or more complex combinations) which also enables auctions to accommodate for more complex products such as complex bid. Arguably, the fact that more sophisticated products are available in auctions increases the liquidity since their constraints can be more easily represented.

In addition, it has been a long lasting debate whether intraday auctions can more efficiently price the cross-border transmission capacity. Indeed, the pricing of transmission capacity through implicit auctions (such as in day-ahead) has proved to be efficient. However, on the other side, some have questioned that - provided a certain frequency of auctions – it is unlikely that large parts of transmission capacity will be sold at once in such auctions (so either all is sold at day-ahead stage, or it is sold gradually in intraday timeframe – for a cost of zero since it is not scarce as long as some capacity remains – or there is no remaining capacity to sell).

Discrete auctions need to be configured depending on the system characteristics and needs (among others to ensure increased liquidity). Changes in the system may affect the suitability of the timing of the intraday auctions.

Continuous trading

Continuous trading provides greater flexibility since trading is always possible. However, continuous trading is deemed efficient only at the condition that a certain level of liquidity exists. Further, it can be that all the available resources are not necessarily available at all time on the market, as traders having out-of-the-money assets may not make the effort to maintain orders for such assets. Further, it is more complex to introduce bidding protocols based on complex or block bids.

[3] Henriot (2014) derives analytically, discrete auctions may lead to lost trading opportunities. If gate closures in auction- based intraday markets are set at times that do not suit the market participants' trading needs, market participants will not trade. If intraday trading needs become apparent after the intraday gate closure (in Italy the shortest gate closures are 4.15 hours before delivery), relevant information cannot be incorporated into the intraday market. Therefore, the early gate closures in auction-based intraday markets may constitute an obstacle to an efficient intraday market operation and may lead to lower trading volumes" (Hagemann & Weber, 2015)

Also partially as a consequence of not ensuring enough liquidity, partially as a consequence of the full disclosure of information associated to continuous trading (prices and quantities submitted are not blind, and can be observed by other agents), there is a risk of not pricing properly cross-border capacity. Typically capacity is allocated at a zero cost (bid and offer spread is zero) on a first come first serve basis.

Complementing an opening session with continuous shorter-term continuous trading potentially allows integrating variable renewable energy (VRE) in a very efficient way (especially in the long term). However, while this design would respect the strong variability of renewable generation it may not be as easy to trade conventional generation because of more simple bidding protocols.

Hybrid

The hybrid design combines the advantages of both (but also the disadvantages).

The German Intraday market allows trading up to 45 minutes ahead of delivery. Consequently, it provides high flexibility and balancing close to real time. This supports players that trade renewable as well as conventional energy. In (EPEXSPOT, 2015), it is pointed out that "since 2011, 15-minute contracts provide greater flexibility to handle intermittency and the daily ramping effects of renewable production, contributing to a more balanced market." Although that liquidity remains relatively low it most likely becomes automatically higher as the share of renewables in the generation mix is to increase. Participants responsible for balancing deviations due to uncertain renewable generation achieve cost optimization spontaneously provided that they are allowed to trade when necessary. The disadvantage of discrete auctions is that they may limit these opportunities, c.f. (EPEXSPOT, 2015) and (Henriot, 2012). Figure 4 provides the volume of energy traded monthly in the intraday market in Germany from March 2012 to March 2013.

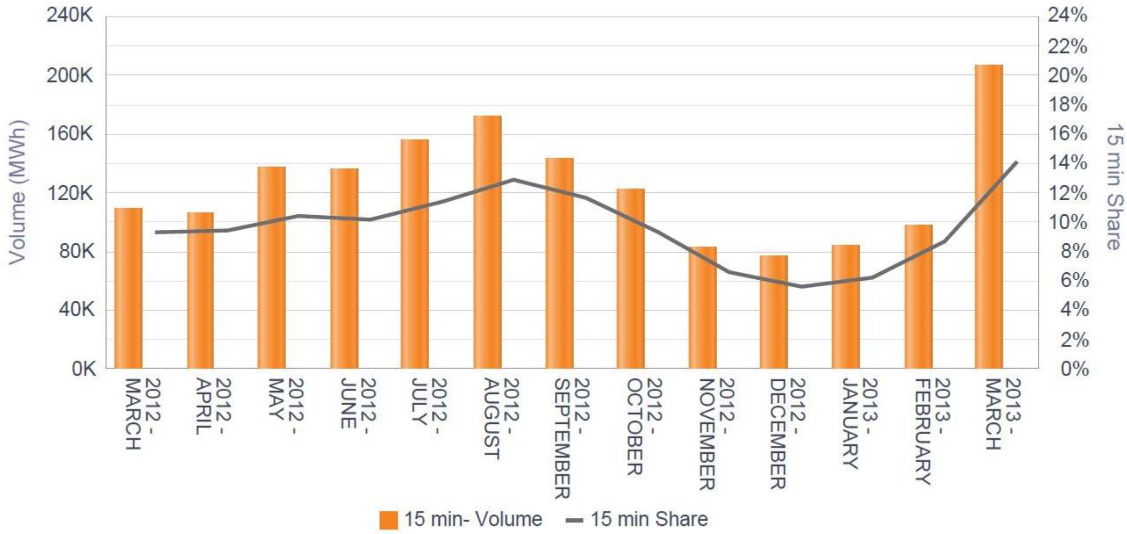

Figure 4: Volume of energy traded in the German intraday market monthly

Implementability

Continuous

Continuous markets are simple to implement from a conceptual point of view. At least if only simple price-quantity orders are allowed. Including more complex types of orders may prove to be a challenge for the short-time period available to clear the market.

There is a large international experience both at national and regional level with this type of markets (for instance in Northern and Central-West Europe).

Discrete intraday auctions

Discrete intraday auctions are also relatively simple to implement, but require more regional coordination (at least some homogenization is needed on the decisions on when to schedule discrete sessions of the markets).

There is international experience at a national level (e.g. Spain, Portugal and Italy). The experience in the regional context is limited in Europe to the simpler case of two interconnected systems (e.g. Spain and Portugal). However, the processes for intraday auctions are expected to mimic – or at least to be largely inspired by - the day-ahead process, which is already largely implemented in Europe.

In the regional context, there is a need to homogenize the timing of the discrete auctions.

Table 2 provides a summary of the assessment made of options for the timing of intraday markets.

Table 2: *Table summarizing the discussion on continuous, discrete and hybrid timing of intraday markets*

		Continuous	Discrete	Hybrid
Efficiency	*Flexibility to trade*	Very Good	Fair	Good
	Liquidity	Fair	Very Good	Good
	Efficiency of the dispatch	Fair	Good +	Good +
	Pricing cross-border capacity	Fair	Very Good	Good
Implementability		Very Good	Good +	Good +

3.3.3 Timing of the gate closure

Efficiency

Bringing it closer to the real time

From the efficiency point of view, bringing it closer to the real time allows a more efficient participation of RES-E given the improvement of forecast accuracy at shorter times and closer to delivery. Bringing the gate closure closer to the real time reduces the timeframe during which the SO can manage system security. However, by defining a closer to real time gate closure (e.g. as in the Nordic market 45 min before delivery where VRE can also bid, or in Belgium and the Netherlands where local trading is possible until 5 minutes before real time) this option would support the integration of renewable generation. Depending on how close this option would actually be set to the real-time market, it may define a timing that reflects and balances the interests of RES and conventional generators.

Moving it away from the real time

Also from the efficiency point of view, it is sometimes claimed that keeping it around one hour before real time, or even moving it away from real time can give more capability to the SO to ensure security of supply while also giving further incentives (when coupled with dual imbalance pricing) to improve forecasting tools. Even if those advantages are true, the disadvantages of a gate closure far away from real time will most-probably overcome that possible advantages.

In this sense, considering the option of “moving the gate closure away from real time”, would be inefficient as found by REserviceS, 2014: *“the longer the time between procurement and delivery the more room for forecast errors occurrence and the less chance for variable generation to take part in the provision of services at reasonable costs”* - highlighting the fact that necessary adjustments can be made more efficiently with close to real time gate closures. Overall, there are existing experiences for both design options. The general conclusion with regard to the above is that the closer to real time option is the more efficient solution, as similarly was found by elia, 2012 and is also stated in the recently adopted network code: *“… gate closure time shall be at most one hour …”* (Official Journal of the European Union, 2015).

Nevertheless, the impact of the timing of the gate closure upon the efficiency (especially liquidity) and implementability criterion will always depend on the timing of the markets as was discussed in the previous section.

Related to the timing of reserve markets, bringing the gate closure closer to the real time allows balancing reserves to be contracted for shorter timeframes (due to a closer to real time energy market).

3.3.4 Timing of reserve markets

Efficiency

Exclusively implementing long-term procurement of reserves clearly restricts VRE participation due to the limited predictability of its generation. Therefore, this option does not reflect the contradicting interests of renewable generators to take part in shorter time frames (due to uncertainty in production). However it can be considered a long-term necessary signal for some plants (e.g. to avoid some thermal units which are required to balance the system to mothball).

Exclusively procuring reserves in the very short-term does not allow the participation of some slower plants. In this respect, some conventional generators prefer day-ahead frames, e.g. for start-up time planning (decision for thermal units is about 6 to 8 hours ahead) (Neuhoff, Ruester, & Schwenen, 2015). The day-ahead seems to be a reasonable time frame to maximize the value of non-flexible resources.

Considering the variant with intraday updates, market players with variable generation have the option to self-balance their deviations. This in turn provides the potential to "reduce the reserve power capacity requirements and costs in the balancing market so that fewer power plants have to operate in an inefficient partial load mode in order to deliver balancing services" (Hagemann & Weber, 2015).

Consequently, a combination of long-term, day-ahead and shorter-term procurement would maximize the value of existing non-flexible sources, while taking advantage of the potential of VRE to participate in the market.

3.4 Conclusions

Increasing penetration levels of intermittent generation is calling for a rethinking of the timing of markets in systems worldwide. Generally speaking, there is a certain consensus on the fact that markets need to be able to react faster to changing conditions.

In order to achieve the previous objective efficiently, it is essential to maximize not only the value of existing flexible resources, but also the value of non-flexible and intermittent resources.

As analyzed in the subtask, this can be achieved following the next recommendations:

- **In the day-ahead time frame**: to maximize efficiency and avoid distortion, the tasks involved by the pre-coupling phase should be pushed to take place as late as possible. Regarding the coupling process, the total time needed to conduct the associated tasks should be as short as possible (while complying with security criteria).
- **In the intraday timeframe**: continuous trading provides greater flexibility since trading is always possible. However, continuous trading is deemed efficient only at the condition that a certain level of liquidity exists. When this is not the case (as shown in some European PXs), a hybrid solution combining discrete and continuous is the best approach.
- **Procurement of reserves**: a combination of long-term, day-ahead and shorter-term procurement can maximize the value of existing non-flexible sources and while taking advantage of the potential of VRE to participate in the market. The proportion to be procured in each timeframe will strongly depend on the particularities of each system.
- **Gate closure**: it should be moved as close as possible to real time (while complying with security criteria).

4 Bidding protocols

Wholesale electricity markets revolve around short-term auctions (so-called day-ahead markets) where generators' energy offers and consumers' bids are matched to determine producers, consumers and market clearing electricity prices for each time interval.

This text-book general framework, however, can be achieved in a number of different ways, and as a matter of fact, short-term electricity auction design has evolved differently in each system worldwide.

There are many relevant design decisions that may differ from one system to another. Here the focus will be on the two most relevant ones:

- The first essential design decision lies in the way generators are allowed to submit their offers (the so-called bidding protocols or bidding formats);
- The second fundamental design decision is about how prices (or more correctly, the remuneration and charges) are determined.

Bidding protocols

By bidding protocols a reference is made to the first essential element of auction design: the format of the bids that can be submitted by agents in the market. It can be seen, that there are two major alternatives in practice, which correspond to the approaches followed at both sides of the Atlantic.

Pricing rules

Despite the good academic properties of the marginal pricing theory applied to electricity markets, electricity auctions pose some relevant challenges that complicate the ideal marginal and uniform pricing scheme.

In particular, in the presence of start-up costs and minimum technical output, a uniform price[4] computed as the marginal cost of the economic dispatch solution cannot be simply calculated since the offer and demand curves become non-convex, i.e. are no longer simple continuous and monotonous curves, and therefore a unique intersect is not always available.

This problem has led to different approaches to calculate the remuneration and charges that can compensate generators for these costs. Generally speaking, these approaches can be classified into two large groups which again correspond to the alternatives followed at both sides of the Atlantic.

The review shows that the design of the bidding protocols and the pricing rules is not completely isolated one from another.

[4] In this document, a uniform price is defined as a price applied to all transactions of a given product..

In this chapter, the major objective is to critically assess the advantages and disadvantages of both, the US and the EU models. To do so, first the two approaches are further described in section4.1. Then the assessment criteria are presented in section4.2. Finally the critical analysis is carried out in section4.3. Section 4.4 presents the conclusions.

4.1 Design options

As it has just been pointed out, there are two major approaches as regards the pricing rules and bidding protocols alternatives. First of all the pricing rules approaches are described in more detail, since it conditions to some extent the alternatives for bidding protocols. Once the pricing rules are reviewed, the differences in the bidding formats are discussed.

4.1.1 Pricing rules

The major problem when clearing electricity markets is that due to non-convexities (start-up, indivisible offers such as the minimum technical output, etc.) it is not possible to obtain an optimal (social-welfare maximizing) dispatch that can be cleared with uniform marginal prices[5].

Due to this impossibility, there is a trade-off when designing the pricing rules in the wholesale market:

- Either obtaining the social-welfare maximizing solution is neither constrained by a financial balance constraint (i.e. sum of all transacted purchases equals sum of all transacted sales) nor by uniform pricing requirements, and consequently additional compensations may be required for some bids (therefore, this pricing approach involves discriminatory remuneration).
- Or the social-welfare maximization is constrained by a financial balance constraint and by uniform pricing (so there are no discriminatory compensations). Consequently, the dispatch is more constrained and there may be "paradoxes" in the results (see below).

Generally speaking, the first approach represents the US ISO/RTOs market design, while the second approach represents the EU PXs market design one. Next we describe them both in more detail:

The US approach

In the US ISO/RTOs markets, both the day-ahead (DA) and the real-time (RT) prices[6] are computed in a similar way. The clearing algorithm in both cases looks for the maximization of the social welfare.

Roughly speaking, prices are calculated ex-post as a result of the social welfare maximizing dispatch. They represent the marginal costs of the system in each node (locational marginal pricing), DA prices are hourly while RT prices have greater granularity (15 – 5 minutes).

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[5] The literature on this topic is extense, see for instance (Sioshansi, 2014), (Ruiz et al., 2012), (van Vyve, 2011), (Gribik et al., 2007), (O'Neill et al., 2007) or (Hogan and Ring, 2003).

[6] A two settlement system is implemented in the US. The first settlement takes place in the day-ahead market at the day-ahead price, this market is purely financial although physical constraints are included and affect price formation. The second settlement is only for differences with respect to the day-ahead market result, which are settled at the real-time market price.

As it has been described, marginal prices do not completely support the so-computed welfare maximizing dispatch since they only include variable production costs. Meaning that some accepted bids do not recover their short-term production costs with these hourly prices. These bids are known as paradoxically accepted bids (PABs). Equivalently, some bids can be rejected although these bids appear to be in the money. These bids are known as paradoxically rejected bids (PRBs).

In order to compensate these paradoxically accepted or rejected bids, in the US a so-called non-linear pricing rule (also known as discriminatory pricing) is implemented. In this way, after obtaining a uniform marginal price (marginal cost) from the clearing model, additional side-payments (aka. make-whole payments or uplift credits) are calculated and provided on a differentiated per generation unit basis. There can be various reasons for these side-payments, first, the marginal pricing approach creates prices that only capture incremental energy costs. A unit that is marginal for most of its commitment period does not collect sufficient inframarginal rents to recover its start-up and no-load costs, and is compensated through these additional payments. Also, a unit with an incremental energy cost above the marginal price may not be allowed to set the price because a technical constraint is forcing its operation (minimum output or minimum up time restriction). Other uplifts are for instance caused when ISOs commit additional units out of the market to ensure reliability.

On the one hand these side-payments solve to some extent the problem of supporting the social-welfare maximizing dispatch with a remuneration scheme, but on the other hand it also poses many other problems, (van Vyve, 2011) among others:

- Allocating the associated costs, based on a cost causality criterion is not obvious (and more precisely, not possible) and can lead to inefficient incentives (Hogan, 2014).
- Truthtelling: the introduction of side-payments reduces the incentive to truly bid based on costs.
- Demand response can be one of the resources more seriously affected by the inefficiencies introduced by the side-payments.

In the US model and in the presence of non-convexities, prices can leave some rejected orders in-the-money (they were rejected to maximize the social-welfare, but they would have unilaterally accepted to produce with the resulting market clearing prices). Side-payments are, however, only provided to committed units and these rejected orders in the money, also referred to paradoxically rejected bids, are not compensated.

The EU approach

As the regulatory context is fundamentally different in Europe compared to the US, European Power Exchanges (PXs) have opted for implementing a uniform pricing approach as there has been no obvious mean to finance side-payments. This means that PXs impose a financial balance constraint and that all transactions for a given period and bidding zone are settled at the same market clearing price.

The price formation of European PXs (and therefore translated in Euphemia to the algorithm used) maximizes the social-welfare while at the same time fulfilling a set of rules:

- Rule 1: Linear pricing approach (no side payments). Because not being compensated for an order accepted although it is out of the money is not acceptable for market participants, paradoxically accepted bids are not an option, or equivalently using the terminology used in European PXs, out of the money orders (i.e. sell orders above the clearing price or purchase orders below the clearing price) are always rejected.
- Rule 2: Only divisible in the money orders (i.e. divisible sell orders below the clearing price or divisible purchase orders above the clearing price) are always accepted. This means that indivisible orders (e.g. an all-or-nothing type of bid, such as a block bid, described below) can be rejected even if in the money.
- Rule 3: At the money orders (i.e. sell or purchase orders with limit prices equal to the clearing price) can be partially accepted.

The previous three rules couple the volume computation with the price computation, leading to a clearing algorithm that is more complicated to solve than the sequential one described for the US (where first the dispatch is computed, and then prices are calculated ex-post). On the other hand, the US model does not only compute transaction prices of the electricity commodity, but cover a larger range of functions such as setting a nodal dispatch with adequate spinning reserves etc.

This higher complexity limits the detail that can be considered in the bidding protocols, while a more detailed modeling of market assets appears predominant in the US model.

Comparing the US and the EU approaches with an illustrative example

For the sake of simplicity we will focus exclusively in a one hour market setting. The conclusions derived from this simple example, can however be extended to more realistic scenarios.

In a single hour electricity auction, and under some ideal conditions, hourly clearing prices and volumes are determined at the intersection of the offer and demand curves. Consequently, and with the exception of some peculiar cases (e.g. vertical overlaps), prices are generally determined by the marginally/fractionally/partially accepted orders.

The presence of non-convexities (e.g. all-or-nothing constraints such as in block orders, minimum income conditions, etc.) complicates the computation of the dispatch and prices since the simple offer-demand intersection rule cannot always be respected.

To illustrate how non-convexities are dealt with in the EU and US approach, the single hour auction is represented in Figure 5. In such a simple example a non-convex order can be introduced, an All or Nothing bid (represented with a dashed blue line).

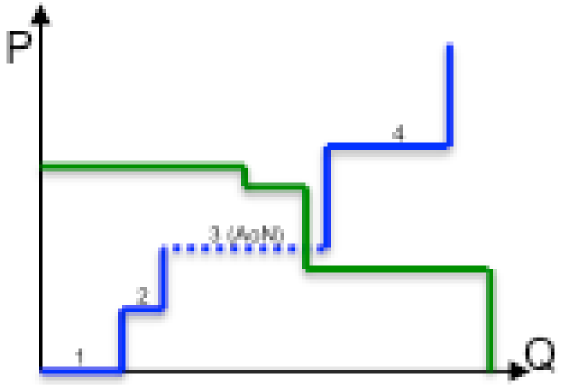

Figure 5: All or Nothing bid

European approach

The algorithm uses as the optimization criterion the total welfare for the acceptance/rejection of orders while complying with the PX rules reviewed above.

Since it is not allowed that out-of–the-money orders are accepted (i.e. paradoxically accepted orders – PABs – are forbidden), for the example illustrated in Figure 5, the algorithm shall reject the solution depicted in Figure 6 (left), because the All-Or-Nothing order would be paradoxically accepted (note that the price P* represented with the black dot would not recover the bid associated cost).

This lead to the acceptance of the solution in Figure 6 (right), since it is allowed that in-the-money orders are rejected (i.e. paradoxically rejected orders – PRBs – are tolerated). The potential losses of PRBs are not compensated.

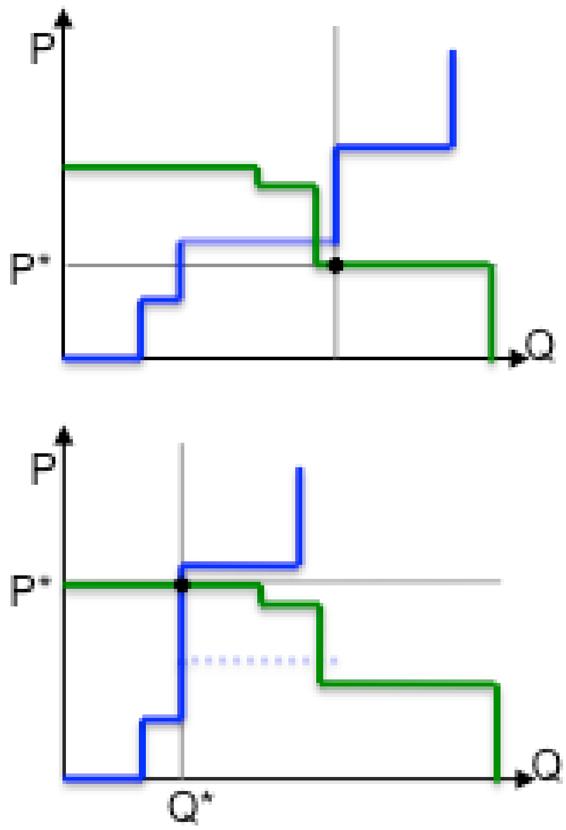

Figure 6: Left: Marginal Clearing price in case the block is accepted. Not allowed in EU model since an order is paradoxically accepted. Right: Marginal Clearing Price in case the block is rejected. This is the solution chosen by the EU model.

US approach

Marginal market clearing prices allow PABs and PRBs, but then discriminatory side-payments are used to eliminate the previous paradoxes.

For the example illustrated in Figure 5 (which is invalid as the All-or-Nothing constraint is not respected), both solutions in Figure 6 are valid solutions, but the solution in the left side of Figure 6 produces higher welfare and therefore will be retained. A side-payment then compensates the loss incurred by the indivisible supply order[7].

As previously described, the rationales of this approach can be summarized as:

- The algorithm uses as its optimization criterion the total welfare.
- The sum of all cash outflows and inflows resulting from the cleared contracts should necessarily net out to zero because of side-payments which can be taken from an external (regulatory) pocket.

[7] Note that in such theoretical examples, one can easily design a case where the side-payments implied are larger than the welfare gained by the approach.

- It is allowed that out-of–the-money orders are accepted and that in-the-money orders are rejected (i.e. paradoxically accepted and rejected orders – PABs & PRBs - are tolerated). The potential losses in such cases are compensated by side payments.

4.1.2 Bidding protocols

Bidding protocols in the US

US ISO (Independent System Operator) markets are based on complex offers (aka multi-part offers), which allow to represent a generating unit operational constraints (minimum run time, minimum down time, start-up/shut-down time, ramp rate up/down, economic minimum/maximum output level) and operating costs (start-up and shut-down cost, no-load cost, incremental energy cost and cost to provide ancillary services, opportunity cost of water in case of hydro resources, etc.). A SCUC (security constrained unit commitment) model dispatches resources maximizing social welfare, which in practice translates into minimizing total production costs for energy and operating reserves, subject to the technical constraints of the system.

Bidding protocols in the EU

When designing a common algorithm for the PCR initiative, one major objective was that of covering all the local requirements at the same time. This has led in practice to an algorithm that is capable of handling a large variety of market order types (most of those originally available in each system). Among others, the most relevant market orders are (see PCR, 2013):

- **Aggregated Hourly Orders:** these are simple hourly price-quantity curves (can be piece-wise or step-wise). These simple types of bid traditionally represented a large proportion of total transactions in many European PXs. As a consequence auctions used to resemble simple ones (with no non-convexities issues arising, see for instance the case of Spain (Vázquez et al., 2014)).
- **Complex Orders:** A complex order is a set of simple hourly orders (price-quantity) corresponding to a single production unit, spreading out along different periods and which are subject to a complex condition that affects the set of hourly orders as a whole. The most important complex conditions are the Minimum Income Condition (i.e. the total income over the day should at least compensate a fixed term and a variable – per MWh produced – term) and the Load Gradient constraint.
- **Basic block Orders:** allow agents to submit a certain interval of consecutive hours where they are willing to produce, and the minimum average price they require to be committed (i.e. it is a minimum income condition over one particular dispatch). There are also profiled block orders, linked block orders and exclusive groups of block orders and flexible block orders.

It is worth noting that there is a fundamental difference between complex orders and block orders: while in the former the cost per MWh produced is represented twice, i.e. by the underlying simple price-quantity hourly bids and by the variable term of the minimum income condition, in the latter production cost is represented only once (there is just one declared minimum average price for the whole block of energy comprised in the hours of production).

4.2 General assessment criteria

In this section, the assessment criteria that will be used to critically analyze the US and the EU approaches are briefly presented.

4.2.1 Efficiency

Marginal cost reflectivity

Marginal cost reflectivity is a desired property of a pricing methodology. However, the notion of marginal cost reflectivity proves difficult in the presence of non-convexities. In particular, all or nothing constraints required by market participants to better reflect their economic and technical constraints (e.g. block orders) conflict with the general marginal clearing price rule that prices are determined at the intersect of the offer and demand curves. This is because such a single intersection might not exist.

Market modelling imperfection costs (diversity of products traded in the market)

It is important to assess if there could be potential inefficiencies derived from not perfectly representing some technical and economic constraints of generation and demand. In particular, the trade-off between the approximations in the modelling of these constraints, the complexity of the underlying market clearing algorithm, and the ease of use for traders is required (see implementability criteria below).

The suitability of the products to reflect the costs and constraints of the different generation technologies (ramps, start-up trajectory, minimum technical output, limited energy resources, storage, demand response etc.) needs to be assessed. The bidding formats should ensure the maximization of the social benefit.

Market transparency

Entire chain of pricing and contracting on such auctions should be open and transparent, while keeping the adequate level of confidentiality required in competitive markets, in order to attract as many potential agents as possible. The transparency level and the information disclosed to agents about the technical aspects of the market-clearing algorithm (requirements, functioning, properties of results), about its daily input and output (bids, network constraints, …) and its market results is a key design element in this respect.

4.2.2 Robustness

It is relevant that the products and the pricing rules prove to be robust in general, and in particular against different potential penetration levels of RES-E and price manipulation or abuse of market power.

4.2.3 Implementability

This relates to how easy the implementation of a market is, or the difficulties authorities and operators may face in its implementation and day-to-day functioning. There are several dimensions to the implementability of a market. They are discussed next:

Computability

Including very complex products can lead to problems extremely difficult to solve.

Simplicity of the market

Implementing very sophisticated and complex products may prove to over-complicate the bidding processes of the agents, while never perfectly fitting the exact needs of all particular cases. It is therefore generally accepted that a certain level of modelling approximation is adequate.

Implementation time and costs

Implementing radical changes or adding extra layers of complexity may require long time and high costs.

4.3 Assessment of design options

Next, the two main approaches to the design of prices and bids (EU and US) are assessed according to main criteria just described.

4.3.1 Efficiency

EU approach

Marginal cost reflectivity: Good

Wherever possible, prices are set by fractionally accepted orders.

In the EU approach agents are incentivized to bid at their marginal costs. However, agents take the risk to be paradoxically rejected when using complex or block bids (this paradoxical rejection does not happen with simple orders).

Market modelling imperfection costs: Fair to Good

This design by nature implies a quite complex price calculation algorithm since prices and accepted volumes are computed simultaneously, possibly restricting the flexibility to implement highly complex orders better representing the economic and technical constraints of agents.

However, since most EU markets are organized on an agent's portfolio basis (as opposed to the US model which is unit specific), it is questionable whether a high level of complexity is effectively required by the market agents.

Market transparency: Very good

Any level of transparency is possible for the algorithm (functioning), its requirements (constraints and properties) and its daily input (e.g. orders, network constraints, …) and output (market prices).

US approach

Marginal cost reflectivity: Fair

Because of side-payments, by exception all agents do not necessarily obtain the same price for the same product (i.e. deviation of uniform pricing rule).

Some generators require side-payments (or make-whole payments or uplift credits) to recover all of their operational costs. Side-payments charges are mostly socialized since a cost-causality basis is difficult to establish and is a source of inefficiencies.

It seems that it would be desirable that more bids involving non-convexities could set the market price. For instance, a common problem in many US markets is the issue of pricing Fast-Start Resources (Pope, 2014).

Regarding side payment charges, concerns are raised that prices should reflect a more ample concept of marginal cost to send proper economic signals, both in the short-term and in the long-term (FERC, 2014).

Market modelling imperfection costs: Very good

Price calculation in such a design is not dependent of the accepted volumes (and therefore can be calculated after the acceptance of volumes); consequently there might be additional room for bid sophistication.

Multi part bids are close to representing most of the constraints and costs components, however, practical computational limitations exist and not all technologies are equally represented. Although current implementation can achieve great efficiency, improvements are needed to properly model novel technologies (e.g. storage is not accurately modelled in all US markets).

The total welfare of the algorithm is not restricted by price constraints; however, the sum of all side-payments should be subtracted from the welfare value.

Market transparency: Very good

Any level of transparency is possible for the algorithm (functioning), its requirements (constraints and properties) and its daily input (e.g. orders, network constraints, …) and output (market prices).

4.3.2 Robustness

EU approach

Robustness against the penetration level of RES-E: Good

The EU approach performs well with respect to this criterion.

Generators (and demand) do not have to make hypothesis anticipating the resulting dispatch when determining their own bids. Therefore the dispatch is robust against difficulties to predict dispatches.

As typically RES (wind and PV in particular) have little All-Or-Nothing type of constraints, higher RES penetration levels facilitate the algorithmic calculations.

Resistance to price manipulation or abuse of market power: Good

The EU approach performs well with respect to this criterion.

In this specific design aspect, the absence of compensation/side-payments and of paradoxically accepted orders reduces strategic behaviour opportunities, since problematic orders are essentially rejected.

In general though, the model is neutral in terms of market manipulation or abuse of market power, which is more a market monitoring and regulatory matter.

US approach

Robustness against the penetration level of RES-E: Very good

The US approach performs very well with respect to this assessment criterion.

Generators do not have to make hypothesis on the resulting dispatch to determine their own bids. Therefore the dispatch is robust against difficulties to predict dispatches.

As typically RES (wind and PV in particular) have little All-Or-Nothing type of constraints, higher RES penetration levels facilitate the algorithmic calculations.

Resistance to price manipulation or abuse of market power: Poor

The US approach performs poorly with respect to this assessment criterion.

In this specific design aspect, the presence of side payments may trigger strategic bidding behaviours. Indeed since paradoxically accepted or rejected orders are compensated, additional regulatory oversight is needed to avoid strategic bidding calling side-payments (e.g. submit all-or-nothing bids at very low price that are compensated because of too large volumes to find counterparts).

In general though, the model is neutral in terms of market manipulation or abuse of market power, which is more a market monitoring and regulatory matter.

4.3.3 Implementability (in Europe)

EU approach

Computability: Good

Despite the fact that the computation is challenging, experience has shown that many EU markets with a large number of non-convex orders can be cleared in the short term simultaneously.

Simplicity: Good

Products are reasonably simple.

Implementation time and cost: <u>Very good</u>

Currently implemented in MRC (multi-regional coupling).

US approach

Computability: <u>Good</u>

As proven by experience.

Compatibility: <u>Good</u>

Simplicity and transparency: <u>Fair</u>

Although it is for the benefit of a more accurate modelling of the economic and technical constraints, products are typically much more complex, thus potentially affecting simplicity and transparency.

Additionally, side-payments are under debate in the US. At the Uplift and Operator Actions Workshops, some panelists addressed issues concerning insufficient transparency of uplift and operator actions

Implementation time and cost: <u>Poor</u>

This would indeed imply major changes in MRC, PCR and PX systems; and an agreement to prioritize this discussion and ultimately agree on the change might take time.

4.4 Conclusions

Table 3 summarizes the assessment carried out in this section. As it can be checked, there is no perfect design. As explained above, non-convexities (start-up, indivisible offers such as the minimum technical output, etc.) do not allow to obtain an optimal (social-welfare maximizing) dispatch that can be cleared with uniform marginal prices. Due to this impossibility, there is a trade-off when designing the pricing rules and bidding protocols in the wholesale market that has led to the two approaches discussed. While the EU PXs approach is superior as regards pricing and truthtelling, the US approach proves to be superior as regards the flexibility offered by the bidding protocols and the computability of the results.

Generally speaking, changing the current design in the EU at the present moment is more than complicated. Not only it requires major changes, but also it would require a major cost-benefit analysis to support the decision and also an agreement among all parts that would most probably take long to be reached (if ever).

Table 3: Summary of the assessment made of the EU and US approaches to the design of energy prices and bids

		European approach	US approach
Eficiency	*Prices (cost reflectivity)*	Good	Fair
	Bidding protocols and dispatch	Fair	Good
Robustness	*RES penetration*	Good	Good
	Market power	Good	Fair
Implementability	*Implementability: computability*	Fair	Good
	Implementability in Europe	Very Good	Fair

5 General design principles for balancing mechanisms in a context of high RES-E penetration

This section reports on the analysis carried out on the appropriate design of balancing markets at European level. The design of these markets is concerned with three main issues:

- Those arrangements that are related to the organization of the procurement of balancing services. These need to achieve a high enough level of competition and flexibility in this market, leading to an increase in the efficiency and safety of system operation.
- Those that are focused on the calculation of imbalance prices to be applied to balancing responsible parties (BRPs). These must provide adequate incentives for BRPs to either keep a balanced position of load and generation they represent or to help the system to restore its balance.
- And the level of coherence achieved between balancing markets and others that are also run at European level, like the short and very short term energy markets including cross-border congestion management schemes.

Next, options for the design of both types of processes, or aspects of balancing markets, are described, and then analyzed, according to the criteria described below.

5.1 Design options for Balancing arrangements

In order to guarantee the balance between generation and demand in real time, TSOs perform the load-frequency control process, which comprises the following actions:

- the Frequency Containment Process, which aims at resolving large generation or load outages by a joint action of Frequency Containment Reserves (FCR) within a Synchronous Area.
- the Frequency Restoration Process, which aims at bringing back the system frequency to its nominal value and replacing the activated FCR through the activation of Frequency Restoration Reserves (FRR). FRR can be either automatically (aFRR) or manually activated (mFRR).
- the Reserve Replacement Process, which aims at replacing the activated FRR, preparing the system to deal with further imbalances, through the activation of Replacement Reserves (RR).

Reserves used by TSOs in order to balance the system in real time are commonly referred as balancing services. In general, TSOs specify one or more products for each type of reserve and procure these products through balancing markets. Balancing services products can be divided into two main categories:

1. Balancing capacity, which refers to the power capacity reserved in advance and kept available to the TSO (i.e. not committed in other markets) for its use when an imbalance occurs in real time;
2. Balancing energy, which refers to the actual variation of generation/consumption used to reestablish the balance between generation and demand in real time.

Each one of these categories can be subdivided into two further categories:

i. Upward reserve: balancing capacity/energy procured to compensate a negative imbalance, i.e. lack of generation or excess of consumption;
ii. Downward reserve: balancing capacity/energy procured to compensate a positive imbalance, i.e. excess of generation or lack of consumption.

The main balancing market design options which can facilitate or hinder the participation of new and smaller agents, such as renewable generation and load units, and, consequently, market liquidity are:

A. Separated *versus* joint procurement of balancing capacity and balancing energy products;
B. Separated *versus* joint procurement of upward and downward balancing capacity products;
C. Existence of technology-specific products;
D. Minimum bid size requirements/possibility of aggregation of individual bids;
E. Pricing of balancing products: marginal *versus* pay-as-bid pricing.

When TSOs deploy balancing power, they actively balance the system. TSOs may also "passively" balance the system by sending a price signal (i.e. the imbalance price) to BRPs to either keep their balance or deviate from their schedules in order to reduce the system overall imbalance in real time (Hirth and Ziegenhagen, 2015). In this sense, balancing arrangements refer not only to balancing market designs but also to imbalance settlement arrangements. Options to consider in this regard follow:

A. Imbalance settlement arrangements: single vs. dual vs. hybrid pricing;
B. Imbalance settlement arrangements: length of the settlement period.

Lastly, coherence between balancing markets and others must be preserved in order for the system operation to be as efficient as possible and also safe. Options to consider in order for actions in balancing and other markets to be coherent follow:

A. Timing of actions: Intraday trading versus preventive balancing actions;
B. Level of interaction among balancing prices and other products (actions in other markets like congestion management).

5.2 Criteria for the assessment of balancing arrangements

According to ACER (2014), the **core elements that need to be harmonized and standardized in order to achieve an efficient and integrated European balancing market**, while taking into account security of supply constraints, are related to: <u>(i) a consistent framework to foster competition among balance service providers</u> (BSPs), <u>(ii) adequate incentives on balance responsible parties</u> (BRPs) to balance themselves or to support the system balance in real time, and <u>(iii) efficiency in balancing actions performed by TSOs</u>. These elements are closely related to ***flexible balancing market designs***, which foster competition among BSPs and market liquidity; ***cost-reflective imbalance settlement arrangements***, which provide incentives BRPs to support the system balance in real time; and ***coherence among market designs implemented***, which contributes to electricity balancing efficiency.

In the following sections, balancing market designs and imbalance settlement arrangement options, as well the coherence among market designs implemented, are assessed against the above-mentioned efficiency criteria, taking into account the object of achieving a well-functioning cross-border European balancing market. In this respect, notice that achieving efficiency in electricity balancing does not always coincide with solving the system imbalance at the minimum global cost (at least in the short-term). Here, efficient balancing arrangements are considered to be the ones that provide adequate incentives for BSPs to invest in (balancing) capacity and for BRPs to support the system balancing in real time. To support the discussion, balancing arrangements in Spain, the Netherlands, Belgium, Germany and Denmark are used as examples[8].

It is important to point out that the integration of European balancing markets depends not only on the harmonization and standardization of balancing arrangements but also on the existence of adequate arrangements related to transmission capacity allocation and models for cross-border balancing purposes. Although this chapter does not assess arrangements for transmission capacity allocation, it is worth mentioning the Framework Guidelines on Electricity Balancing (FG EB) establishes that the Network Code on Electricity Balancing (NC EB) shall be consistent with the Network Code on Capacity Allocation and Congestion management (NC CACM) in what respects the access to cross-border capacities (ACER, 2012). According to the NC CACM, transmission capacity must be allocated through implicit allocation methods in the day-ahead and intraday time frames (ENTSO-E, 2012).

Regarding the models for cross-border procurement of balancing capacity and balancing energy products, currently, there are two: the TSO-TSO model and the TSO-BSP model. In the TSO-TSO model all interactions with a BSP connected to another TSO's control area are carried on through the connecting TSO (i.e. TSO responsible for the control area to which the BSP is connected). In the TSO-BSP model one or more BSPs have a contractual relationship with the requesting TSO/TSOs (the requesting TSO is the one who procures balancing services' products from BSPs connected outside its responsibility area). The FG EB establishes that the future EU-wide electricity balancing market (i.e. activation of balancing energy) should be based on the TSO-TSO model.

[8]More details on current Spanish balancing arrangements can be found in Fernandes et al. (2015), and Chaves-Ávila and Fernandes (2014); a complete description of the Dutch, Belgium and German balancing mechanisms is provided by E-Bridge Consulting (2014); finally, the Danish balancing arrangements can be found in Energinet.dk (2008) and Energinet.dk (2012).

5.3 Assessment of balancing arrangements

5.3.1 Balancing market design options

Separated versus joint procurement of balancing capacity and balancing energy products

Joint procurement of balancing capacity and balancing energy products refer to a market arrangement according to which only BSPs with a contract for the provision of balancing capacity can be activated in real time and provide balancing energy to the TSO. Examples of markets with this design include the Spanish and the Danish aFRR markets, and the German aFRR and mFRR markets.

Separated procurement of balancing capacity and energy products refer to a market arrangement according to which BSPs without having a contract for the provision of balancing capacity can be present bids to balancing energy "market". In case these bids are activated in real time, BSPs are entitled to an energy payment corresponding to the provision of balancing energy[9]. BSPs with a contract for balancing capacity provision receive a capacity payment for this service. These BSPs have the obligation to offer, at least, the whole amount of balancing capacity specified in the contract to the balancing energy market. In case they are activated in real time, apart from the capacity payment, they also receive a payment for balancing energy provision. Examples of markets under this design include the Belgian and the Dutch aFRR and mFRR markets, and the Danish mFRR market.

One of the main arguments against the joint procurement of balancing capacity and balancing energy products is that it may limit or even prevent the participation of renewable producers and other small players since, in general, the gate-closure for capacity products have long lead-times[10]. For instance, in Spain, balancing capacity is procured one day before real time; in Germany balancing capacity is guaranteed one week before real time. In the case of intermittent renewable generators these gate-closure clearly imposes a barrier to entrance. Figure 7 shows how average wind production forecast errors increase for longer forecast lead-times.

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[9] It is worth mentioning that the payment corresponding to the provision of upward balancing energy is positive in the sense that the TSO pays the BSP) and negative, in the sense that the BSP pays the TSO, in case of downward balancing energy provision. In case of negative market prices, payments' flows change.

[10] Lead-time refers to the period of time comprised between the gate-closure for the presentation of bids and real time operation.

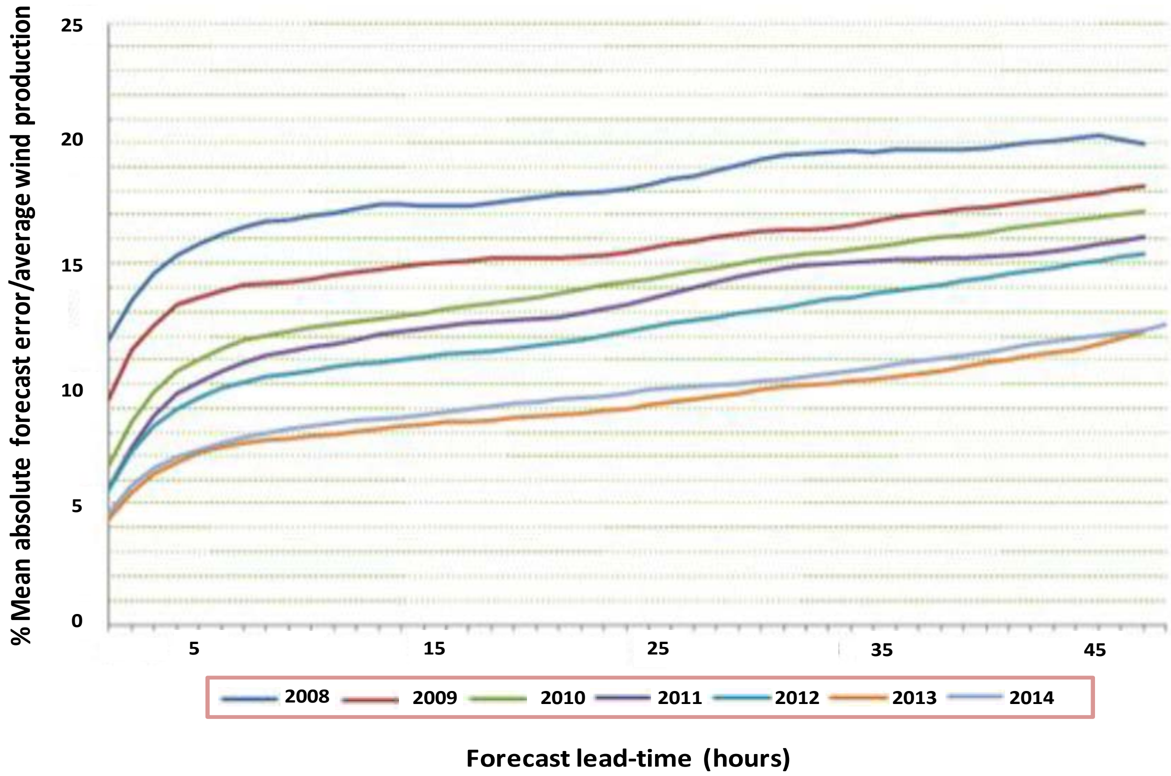


Figure 7: Average aggregated wind production forecast errors calculated by the Spanish TSO prediction tool SIPREOLICO

Under the Dutch market design, although balancing capacity is contracted one year in advance, balancing energy bids, including from BSPs without a contract for balancing capacity provision, can be submitted until one hour before real time operation. In Denmark, mFRR balancing capacity is contracted one day in advance, but bids for balancing energy provision can be placed until 45 minutes before real time operation.

Barriers to the entrance of new potential service providers, such as renewable generators and consumption units, may undermine competition and, consequently, efficiency in balancing services procurement. Apart from this, efficiency can also be compromised due to the fact that actual service provision costs are more likely to be revealed when different products are procured separately; i.e. cross-subsidy among products is avoided, contributing to higher transparency and market liquidity.

Finally, the joint procurement of balancing capacity and energy products could limit up to a great extent the harmonization of balancing markets across borders and, consequently, prevent cross-border trading. This can be explained by the fact that flexibility in balancing capacity markets is much more limited than flexibility in balancing energy markets: while balancing energy is activated to manage imbalances between generation and demand in real time, balancing capacity is procured to guarantee security of supply in longer time frames. Consequently, arrangements for the procurement of balancing capacity can vary greatly depending on each power systems structural characteristics and security of supply needs. In fact, the current version of the Network Code on Electricity Balancing (ENTSO-E, 2014) gives much more freedom to TSOs when designing balancing capacity products in comparison to balancing energy products.

Taking into account the objective of achieving an efficient and integrated European balancing market, the ***separated procurement of balancing capacity and balancing energy products is a preferable market design option when compared to joint procurement of products***. Separated procurement of balancing capacity and balancing energy products together with gate-closures for balancing energy bids close to real time operation, facilitates the participation of renewable producers and new potential service providers. In this respect, the Framework Guidelines on Electricity Balancing (FG EB) requires that TSOs allow BSPs to place (or update) bids for balancing energy as close to real time as possible and at least up to one hour before real time (ACER, 2012).

Separated versus joint procurement of upward and downward balancing capacity products

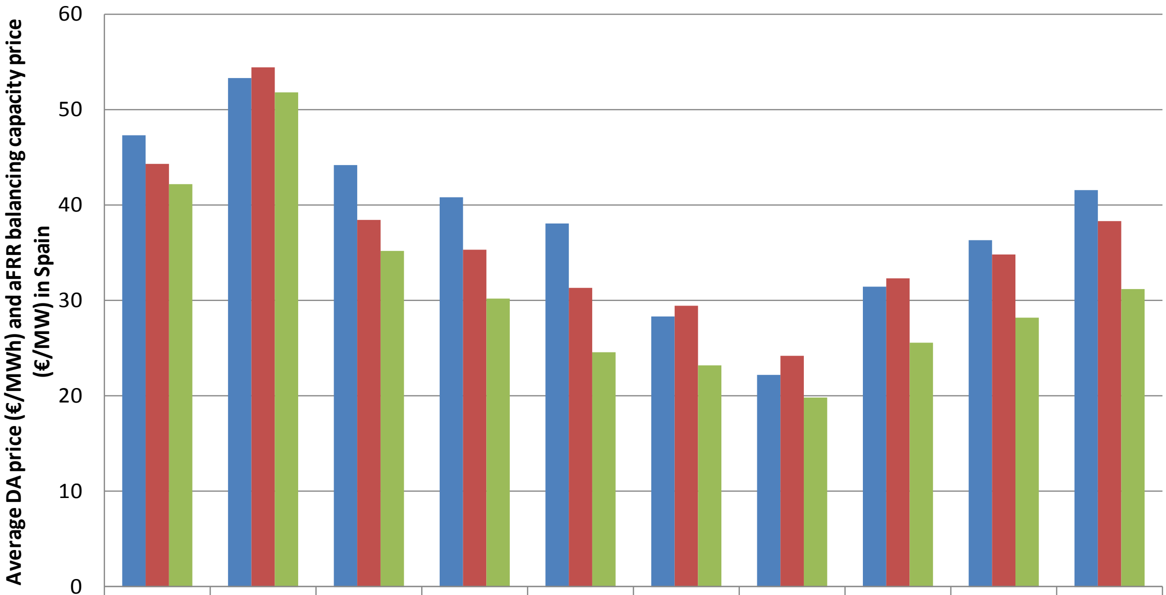
Joint procurement of upward and downward balancing capacity products refer to a market arrangement under which BSPs must present a single bid for the provision of both products. The Spanish and the Danish TSOs procure upward and downward aFRR balancing capacity as a single product. This market design may impose barriers to the participation of renewable generators since the costs incurred by these producers to provide upward capacity can differ greatly from the costs of providing downward balancing capacity. This is related to the fact that, in order to provide upward capacity, renewable units would have to produce below its maximum (potential) production level (according to primary resource - e.g. wind – availability). In this case, producers incur an opportunity cost which corresponds to the revenue that they could obtain from selling the “curtailed” power in the spot market.

Regarding this, levels of wind power curtailment required for the participation of wind generators in the Spanish aFRR market were estimated under the European project Twenties [11]. The study was performed with an aggregated wind power installed capacity of 5,270 MW. According to the results of the analysis, wind curtailment requirements could vary between 19% and 33% of the total installed capacity considering forecast error levels corresponding to market lead times of 15 and 75 minutes, respectively (García-González, 2013). Wind production variability within a time resolution of 15 minutes (aFRR deployment time) was also considered in the study. Notice that curtailment levels can be significantly higher when longer market lead-times (for instance, 24 hours or more) are considered.

Under joint procurement of upward and downward balancing capacity products, the participation renewable producers in balancing capacity markets would greatly depend on the spread between balancing capacity prices and spot market prices, which should compensate for the opportunity cost of curtailing renewable production that could be sold in day-ahead or intraday markets instead. Figure 8 presents yearly average day-ahead (DA) market and aFRR balancing capacity prices and average DA and aFRR capacity prices under different levels of aggregated wind capacity factor (i.e. % actual production/installed capacity) in Spain. The figure clearly shows the influence of wind production on market prices: for higher levels of wind production, day-ahead

[11] www.twenties-project.eu

market prices decrease while aFRR capacity prices increase. The latter is mainly associated to the higher cost of downward balancing capacity provision by thermal units when wind (and other renewable) production levels are high, in particular during off-peak hours when thermal power plants are operating at levels very close to their minimum output values (García-González, 2013). In this sense, under such operating conditions, the costs incurred by renewable producers to provide downward balancing could be significantly lower than the costs faced by thermal generation units.



	DA	DA (cf<20%)	DA (cf≥20%)	DA (cf≥30%)	DA (cf≥40%)	aFRR	aFRR (cf<20%)	aFRR (cf≥20%)	aFRR (cf≥30%)	aFRR (cf≥40%)
2012	47	53	44	41	38	28	22	31	36	42
2013	44	54	38	35	31	29	24	32	35	38
2014	42	52	35	30	25	23	20	26	28	31

Figure 8: Average day-ahead (DA) market and aFRR balancing capacity prices for different wind capacity factor levels (cf) in Spain

Table 4 shows maximum and average hourly differences between a FRR balancing capacity and day-ahead market prices for hours during which a FRR market prices are higher than day-ahead prices for different levels of wind capacity factor. It can be noticed that the lowest price differences are observed for wind capacity factors lower than 20%. Given the influence of renewable production on market prices and the fact that relative forecast errors increase for lower production levels, it is reasonable to assume that only under very specific circumstances it would be profitable for renewable generators to participate in the aFRR capacity provision when the production factor is low than 20% under joint procurement of upward and downward balancing capacity. The table shows that more favorable conditions are presented during a limited number of hours within the year.

Table 4: Day-ahead (DA) market and aFRR balancing capacity price differences in Spain

		Wind capacity factor			
		<20%	≥20%	≥30%	≥40%
2012	Max. price difference when aFRR price > DA price	48	180	180	180
	Average price difference when aFRR price > DA price	**13**	**31**	**35**	**42**
	% number of hours when aFRR price > DA price	1%	16%	13%	7%
2013	Max. price difference when aFRR price > DA price	139	237	197	181
	Average price difference when aFRR price > DA price	**28**	**32**	**35**	**39**
	% number of hours when aFRR price > DA price	2%	22%	17%	11%
2014	Max. price difference when aFRR price > DA price	50	136	136	136
	Average price difference when aFRR price > DA price	**12**	**25**	**27**	**28**
	% number of hours when aFRR price > DA price	2%	19%	15%	10%

Entrance barriers could compromise not only liquidity in balancing capacity markets but also limit a higher integration of renewable generation. Furthermore, as previously discussed, market transparency and efficiency can also be undermined by the fact that, typically, the price of the single product is determined by the sub-product (in the case, either upward or downward balancing capacity) of highest cost (as previously mentioned, under certain operation conditions the costs of providing upward and downward balancing capacity can vary significantly). Therefore, the ***separated procurement of upward and downward balancing capacity would contribute to increase the balancing market efficiency***.

Existence of technology–specific products

Technology-specific products refer to products that, according to market arrangements, can only be provided by specific agents. An example of technology-specific market is the Additional Upward Reserve market in Spain, through which the Spanish TSO procures upward RR capacity. Before the creation of this market, there was no specific mechanism to guarantee RR capacity provision (i.e. only RR energy is procured in the RR market): in case available RR capacity resulting from the DA market schedule was below the day-ahead RR requirements, the TSO would redispatch thermal generation through the congestion management procedure[12]. Due to the increasing integration of renewable generation in the day-ahead market and, consequently, the growing need to redispatch thermal units for balancing purposes, the Spanish TSO created the additional upward reserve market. Accordingly, this market is only called when available RR capacity resulting from the DA market schedule is lower than the day-ahead RR requirements. Only thermal units not committed in the DA market are allowed to present bids to this market. In practice, this market only separates the “dispatch” of thermal units for balancing purposes from the dispatch of thermal units for congestion management purposes. If a competitive and efficient

[12]A detailed description of the redispatch of thermal generators for balancing purposes is provided by Gil et al. (2010).

integrated balancing market is to be achieved, ***all potential providers should be allowed to participate in all balancing markets as long as they comply with the technical requirements for balancing service provision***.

Minimum bid size requirements/possibility of aggregation of individual bids

Minimum bid size refers to the minimum balancing power that must be offered by a single BSP in order to participate in balancing markets. Depending on the product minimum bid size, small generation and load units may be prevented from participating in balancing markets if aggregation of individual units' offers (for compliance with minimum bid size) is not allowed. This is the case of balancing markets in Spain where bids must be sent by individual (generation) units. In the Spanish case, the minimum bid size for balancing products is 10 MW, while 23% of wind units and 48% of solar units are smaller than 10 MW; consequently, these units could not participate in balancing services' provision. Taking into account that intermittent renewable production can be subjected to important forecast errors, even more units would be prevented from participating in balancing markets due to this minimum bid size requirement. Other European countries require smaller minimum bid sizes for balancing services provision. For instance, in Germany, Belgium and the Netherlands minimum bid sizes are 1 MW, 4 MW and 5 MW, respectively.

To foster the participation of small units in balancing markets, smaller minimum bid size should be required and the aggregation of several units should be facilitated. It should be noted that aggregated forecasts are more accurate, which could lead to a more reliable participation of renewable producers in balancing markets.

Pricing of balancing products: marginal versus pay-as-bid pricing

Pricing of balancing products is typically based either on pay-as-bid or marginal pricing. Several European countries combine pay-as-bids payments for balancing products with average imbalance prices aiming at mitigating market power and providing less volatile prices. Nevertheless, pay-as-bid pricing provides incentives to market parties to submit bids as close as possible to the expected marginal price, which is more difficult for small players that do not have the same possibilities to forecast prices. Therefore, it may act as an entry barrier and undermine competition within balancing markets. In general, it is accepted that marginal prices lead to a more efficient allocation of resources. When balancing services are scarce and the costs of balancing the system rise sharply with the volume of imbalances, marginal prices turn out significantly higher than average ones. Since it reflects costs at the margin, it encourages BSPs to invest in appropriate generation capacity and at the same time gives BRPs a greater incentive to avoid energy imbalances (Vandezande, 2011). Consequently, ***marginal pricing leads to more efficient balancing markets***.

5.3.2 Imbalance settlement arrangement options

In order to balance the system in real time and guarantee operational security, TSOs deploy balancing services. The costs associated with these services typically involve the settlement of previously contracted balancing capacity (€/MW) and balancing energy activated in real time (€/MWh). According to the cost-causality principle, balancing costs should be allocated to market parties responsible for imbalances. However, while payments related to the provision of balancing energy are based on the period of actual delivery of balancing power to compensate real time imbalances, payments related to the provision of balancing capacity are made beforehand and for a time period far exceeding the period of energy delivery (and actual imbalances). Apart from this, in several cases, (balancing) capacity is contracted to deal not only with imbalances but also with network congestions. Consequently, procurement costs of balancing capacity cannot be directly attributed to imbalanced BRPs. For this reason, balancing capacity costs are, in most cases, socialized among consumers while balancing energy costs are allocated to imbalanced BRPs through imbalance prices. Furthermore, ***balancing capacity needs and costs may vary significantly across power systems; taking into account the objective of creating a cross-border balancing market, balancing costs should not be recovered through imbalance prices so that incentives for BRPs located in different control areas to support the system balance in real time are not distorted.***

Taking this into account, **cost-reflective imbalance prices** are defined in this assessment as prices that correctly pass on balancing energy costs to responsible market parties in such a way that payments and revenues resulting from the settlement of balancing energy between the TSO and BSPs and payments and revenues resulting from the settlement imbalances between the TSO and BRPs (**Error! Reference source not found.**) are balanced.

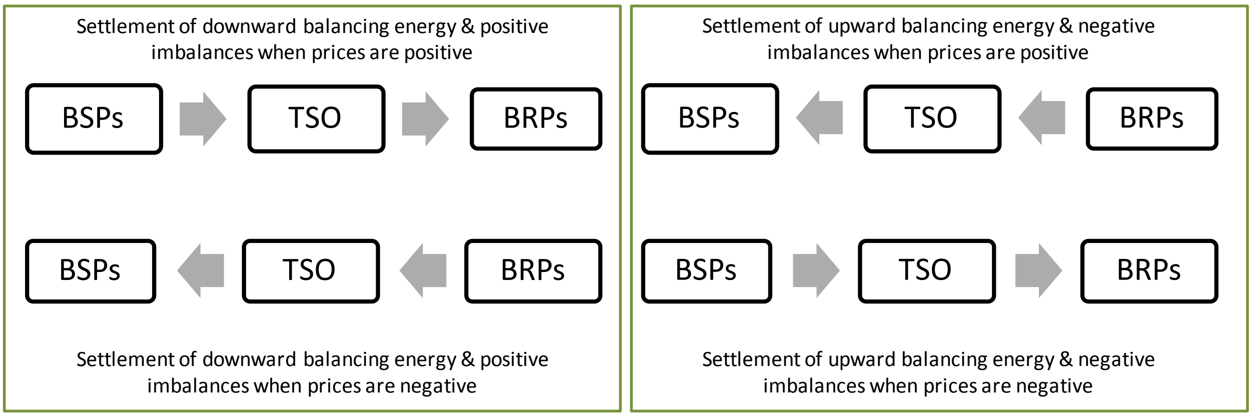


Figure 9: Settlement of balancing energy and imbalances – payment flows. Source: Fernandes et al. (2015)

Apart from activating balancing resources, TSOs may also balance the system in a passive way by providing adequate conditions and incentives to BRPs to support the system balance in real time (Chaves-Ávila et al., 2013; Grande et al., 2008). A main pre-condition for effective ***passive balancing*** is that information regarding the system balance state – i.e. volumes and prices of activated balancing energy – is published shortly after real time (i.e. once balancing energy bids are activated). In principle, this information would allow BRPs to forecast imbalance prices and respond to the system balance state accordingly (Hirth and Ziegenhagen, 2015).

In this respect, according to the recently published recommendation of ACER on the NC EB, imbalances must be settled at a price that reflects the real-time value of energy in such a way that BRPs are incentivized to be in balance during real time and, if allowed within the terms and conditions related to balancing, to respond adequately to the information close to real-time on the system imbalance and imbalance price (ACER, 2015). In practice, this means that BRPs may be incentivized to deviate from their expected production/consumption whenever this helps the system to reduce its overall imbalance.

In this context, the importance of cost-reflective imbalance prices is significantly increased: if imbalance prices do not properly reflect the system balancing needs/costs in real time, BRPs may have distorted incentives and worsen the system imbalance in real time. This is also valid for a cross-border balancing market: distorted imbalance prices across countries/control areas may incentivize BRPs to worsen the system imbalance within a certain area. If, on the other hand, imbalance prices are cost-reflective, passive balancing could partially replace the activation of (more expensive) balancing power, especially from slower reserves, and, consequently, contribute to the reduction of costs associated to the procurement of balancing services. Furthermore it could also facilitate the participation of intermittent renewable generators in electricity balancing while contributing to the reduction of renewable production imbalance costs.

It is important to point out that the calculation of cost-reflective imbalance prices depends not only on the imbalance pricing system but also on the existence of adequate balancing arrangements. This is discussed in the following sections.

Imbalance pricing system

Imbalances can be settled under either a single or a dual pricing scheme. Under a single-price system, the same imbalance price is applied to BRPs with short and long positions. Under a dual imbalance pricing scheme, different imbalance prices are applied to BRPs with long and short positions. While BRPs that aggravate the system imbalance (i.e. BRPs that deviate in the same direction of the overall system imbalance) are settled at an imbalance price based on the price of activated balancing energy, BRPs that reduce the system imbalance (i.e. BRPs that deviate in the opposite direction of the system overall imbalance) are typically settled based on the day-ahead (or other spot) market price (Vandezande et al., 2010).

Table 5 provides a general overview of imbalance prices applied to imbalanced BRPs under single and dual pricing systems. In the table, MP_{dw} and MP_{up} correspond to the marginal prices of downward and upward reserve activated within the imbalance settlement period, respectively; AP_{dw} and AP_{up} correspond to the average prices of all downward and upward reserve activated within the imbalance settlement period, respectively; and DA_p corresponds to the day-ahead market price. Regarding imbalance prices, it is worth mentioning that the day-ahead market price is commonly set as a reference for minimum and maximum imbalance prices applied to, respectively, short and long BRPs that aggravate the system imbalance. Furthermore, in some countries, an incentive component (or so-called penalty) is added to the imbalance price applied to BRPs that aggravate the system imbalance[13] in order to provide a stronger incentive for those BRPs to keep their balance.

Table 5: Imbalance prices under single and dual pricing systems

	System imbalance

[13] In some systems this incentive component is always active (e.g. France) while in other systems the incentive component is only active when the system imbalance reaches a certain threshold (e.g. Germany).

			Positive (long)	Negative (short)
Single-price system	BRP imbalance	Positive (long)	$+AP_{dw}\ or\ MP_{dw}$	$+AP_{up}\ or\ MP_{up}$
		Negative (short)	$-AP_{dw}\ or\ MP_{dw}$	$-AP_{up}\ or\ MP_{up}$
Dual-price system	BRP imbalance	Positive (long)	$+AP_{dw}\ or\ MP_{dw}$	$+DA_p$
		Negative (short)	$-DA_p$	$-AP_{up}\ or\ MP_{up}$

In order to make clearer the implications in implementing a single pricing or a dual pricing system, a numerical example of the settlement of balancing energy and energy imbalances under both systems is provided in Table 6. For simplification purposes, the following assumptions are considered:

- The system has three BRPs: BRP_1 has an absolute imbalance of 30 MWh and contributes to the system's overall imbalance; BRP_2 has an absolute imbalance of 20 MWh and reduces the system's overall imbalance; BRP_3 is balanced and is also a BSP which provides 10 MWh of balancing energy to balance the system.
- Two settlement periods are analyzed: ISP1 - the system is long; ISP2 - the system is short. In ISP1, BRP_1 is long, BRP_2 is short, and BRP_3 provides downward balancing energy. In ISP2, BRP_1 is short; BRP_2 is long; and BRP_3 provides upward balancing energy.
- Intraday trading is not considered.
- Marginal prices of activated reserve are used for the settlement of imbalances in both cases (single and dual imbalance prices). Typically, in power systems where thermal power plants participate in balancing services' provision prices of upward balancing energy are higher than day-ahead market prices and prices of downward balancing energy are lower than day-ahead market prices. Accordingly, the following prices are considered: MP_{up} = 60; DA_p = 50 €/MWh; MP_{dw} = 40 €/MWh.

Table 6: Example of settlement of balancing energy and energy imbalances between the TSO and BRPs

	ISP1: System is long			ISP2: System is short	
	Single-price	Dual-price		Single-price	Dual-price
BRP_1 (long)	30*40 = **1,200€**	30*40 = **1,200€**	BRP_1 (short)	-30*60 = **-1,800€**	-30*60 = **-1,800€**
BRP_2 (short)	-20*40 = **-800€**	-20*50 = **-1,000€**	BRP_2 (long)	20*60 = **1,200€**	20*50 = **1,000€**
BRP_3 (BSP)	-10*40 = **-400€**	-10*40 = **-400€**	BRP_3 (BSP)	10*60 = **600€**	10*60 = **600€**
TSO's net position	**0€**	**200€**	TSO's net position	**0€**	**200€**

It can be observed in Table 6 that under the dual-price system there is a "net income" resulting from the imbalance settlement (TSO's net position). Notice that if an incentive component is added to the imbalance price applied to BRPs that aggravate the system imbalance, there would be also an "extra" income resulting from the settlement of imbalances and balancing energy under a single pricing system; under a dual pricing system the "net income" would be even higher.

The net income resulting from the settlement of balancing energy and imbalances under dual pricing is typically used to generate extra revenues to reduce other balancing costs – which are passed through transmission tariffs – such as costs related to intra-settlement period imbalances and balancing capacity payments. In this respect, even if the TSO use this extra revenue to reduce transmission tariffs, this would entail a transfer of money from inflexible users – such as wind and other intermittent renewable generators – to average users. This transfer of money put small players at a disadvantage in comparison to large players, which can net their imbalances and face lower imbalance costs (Chaves-Ávila et al., 2013; Hiroux and Saguan, 2010; Vandezande et al., 2010). Furthermore, according to ACER (2015), imbalance prices should not include any other costs of balancing, such as procurement costs of balancing capacity, administrative costs or other costs related to balancing[14]. This is an essential condition to the harmonization of imbalance prices across Europe. Table 7 shows the net positions of BRP$_1$ and BRP$_2$ compared to the case in which they do not deviate from their market schedules and the net position of BRP$_3$ in comparison to the case in which it does not provide balancing energy. It can be observed that, under both imbalance pricing schemes, BRPs which aggravate the overall system imbalance (represented by BRP$_1$) are financially penalized for their deviations and BRPs which provide balancing energy to the system (represented by BRP$_3$) are rewarded (on top of the day-ahead market price) the difference between the price of selling balancing energy and the day-ahead market price. However, the situation of BRPs which contribute to reduce the overall system imbalance (represented by BRP$_2$) changes according to the imbalance price design: under single imbalance pricing, they are rewarded the difference between the price of balancing energy and the day-ahead market price, while under dual imbalance pricing, their net position does not change in respect to the situation in which they do not deviate from the day-ahead market schedule.

Table 7: Example of net positions of BRPs in respect to the day-ahead market price

	ISP1: System is long			ISP2: System is short	
	Single-price	Dual-price		Single-price	Dual-price
BRP$_1$ (long)	30*(40-50) = -300€	30*(40-50) = -300€	BRP$_1$ (short)	-30*(60-50) = -300€	-30*(60-50) = -300€
BRP$_2$ (short)	-20*(40-50) = 200€	-20*(50-50) = 0€	BRP$_2$ (long)	20*(60-50) = 200€	20*(50-50) = 0€
BRP$_3$ (BSP)	-10*(40-50) = 100€	-10*(40-50) = 100€	BRP$_3$ (BSP)	10*(60-50) = 100€	10*(60-50) = 100€

While under single pricing BRPs that support the system balance are settled as balancing service providers, dual pricing is generally implemented to incentivize all BRPs to follow their schedules regardless the system imbalance direction - i.e. to not create a short position if they expect the system imbalance to be long and vice-versa. In pricinple, this goes against the concept of passive balancing according to which BRPs are incentivized to actively respond to the system balance state very close to real time operation. It is worth mentioning that, currently, while some countries already incentivize passive balancing (e.g. Belgium and the Netherlands), other countries legally prevent BRPs to deviate from their schedules on purpose (e.g. Germany). As previously

[14] These costs should be recovered through other settlements in order to ensure cost-reflectivity.

mentioned, passive balancing could contribute to reduce the activation of balancing power in real time, which, in its turn, could reduce the amount of contracted balancing capacity.

Therefore, ***under adequate balancing arrangements, single imbalance pricing leads to higher efficiency in electricity balancing***. However, in the presence of market distortions, single pricing could provide incentives to BRPs to worsen the system imbalance, as discussed in the following sections.

The imbalance settlement period

The imbalance settlement period refers to the period of time for which imbalances are calculated. In European countries, settlement periods vary from 15 minutes (e.g. Belgium, the Netherlands, Germany, Switzerland, and Austria), 30 minutes (e.g. France), up to 1 hour (e.g. Portugal, Spain, and the Nordic countries). Short settlement periods contribute to a more cost-reflective imbalance settlement. This can be explained by the fact that BRPs that have been out of balance within a settlement period may be balanced over the whole period. Consequently, the costs incurred by the TSO to balance the system in real time cannot be properly allocated to the responsible market party.

Related to the former, long settlement periods also contribute to the activation of both upward and downward balancing energy bids within a single settlement period, in particular in power systems under high penetration of intermittent renewable generation. In this regard, intra-hour variability of wind production can be significantly higher when compared to variability within reduced timeframes (e.g. lower than 30 minutes), as reported by Nazir and Bouffard (2012). **Under a single imbalance pricing system, it is unlikely that balancing energy costs can be fully recovered when upward and downward balancing energy bids are activated within a single settlement period** since imbalance prices are determined by the net amount of activated balancing energy.

To demonstrate how the activation of upward and downward balancing energy bids increase for longer settlement periods, information regarding the activation of reserves within 15-minute periods is taken from the Dutch TSO webpage[15]. Based on this information, Table 8 presents the percentage number of settlement periods with the activation of both upward and downward balancing energy bids for 15-minute, 30-minute and hourly periods in the Netherlands during 2012, 2013 and 2014. It can be observed in the table how the activation of both upward and downward balancing energy bids increase for longer settlement periods.

Table 8: Percentage of number of settlement periods with activation of both upward and downward balancing energy

	Netherlands		
	15-minute	30-minute	Hourly
2012	11.5%	27.1%	45.3%
2013	12.5%	28.5%	45.2%
2014	6.9%	20.6%	38.5%

[15]http://www.tennet.org/english/operational_management/export_data.aspx

An example of the impact of long settlement periods on the settlement of imbalances and balancing energy is shown in Table 9 and Table 10. Table 9 shows imbalances and Table 10 the settlement of balancing energy and imbalances for hourly and quarterly-hour imbalance settlement periods (ISPs). For simplification purposes, single imbalance pricing based on the marginal price of activated reserve is applied (it is considered that MP_{up} = 60 and MP_{dw} = 40 €/MWh). Also, it is considered that the same balancing energy prices apply to all settlement periods. Notice that the settlement of balancing energy is the same regardless the imbalance settlement period considered.

Table 9: Example of imbalances within hourly and quarterly-hour ISPs

	BRP_1		BRP_2		Balancing energy
	Schedule	Production	Schedule	Production	
ISP_1: 00:00 – 01:00	100	100	100	90	10
ISP_1: 00:00 – 00:15	25	20	25	20	10
ISP_2: 00:15 – 00:30	25	20	25	20	10
ISP_3: 00:30 – 00:45	25	25	25	25	0
ISP_4: 00:45 – 01:00	25	35	25	25	-10

Table 10 shows that for settlement periods of 15 minutes payments and revenues resulting from the settlement of imbalances and balancing energy are balanced (i.e. the net income resulting from this settlement is zero)[16]. When the imbalance settlement period is increased to one hour, the net income resulting from the settlement of balancing energy and imbalances is negative. This is explained by the fact the balancing costs caused by BRP_1 cannot be allocated to this BRP since it is balanced over the whole settlement period. According to this, ***shorter imbalance settlement periods contribute to a more cost-reflective calculation of imbalance prices***.

Table 10: Settlement of imbalances within hourly and quarterly-hour ISPs

ISP	BRP_1	BRP_2	Balancing energy	TSO's position
ISP_1: 00:00 – 01:00	Balanced	-10*60 = - 600	(20*60) = 1,200 (-10*40) = -400	600-1,200+400 = -200
ISP_1: 00:00 – 00:15	-5*60 = -300	-5*60 = -300	10*60 = 600	0
ISP_2: 00:15 – 00:30	-5*60 = -300	-5*60 = -300	10*60 = 600	0
ISP_3: 00:30 – 00:45	Balanced	Balanced	0	0
ISP_4: 00:45 – 01:00	10*40 = 400	Balanced	-10*40 = -400	-400 + 400 = 0

In this respect, it is worth pointing out that even within a 15-minute imbalance settlement period, intra-settlement imbalances cannot be completely avoided, as shown in Table 8. In order avoid distorted incentives on BRPs and insufficient income resulting from the settlement of balancing energy and imbalances, the Dutch TSO applies a combination of single and dual imbalance pricing based on the system regulation state, according to Table 11. The regulation state "-1"

[16] It is assumed that the system overall imbalance is positive or negative within the 15-minute settlement period (i.e. balancing energy is activated in only one direction).

refer to the activation of only downward balancing energy bids within a settlement period; the regulation state "+1" refers to settlement periods with the activation of upward balancing energy bids only; finally, the regulation state "2" refer to settlement periods with the activation of both upward and downward balancing energy bids (TenneT, 2011). Notice that the dual pricing applied under the regulation state "2" is based on the price of activated reserves for both BRPs aggravating and reducing the system overall imbalance within the settlement period. This incentivizes both types of BRPs to keep balanced positions whenever the system overall imbalance cannot be anticipated by market parties. The Dutch TSO strongly incentivizes passive balancing and publishes information on the volume and prices of activated balancing energy bids within 3 minutes after real time.

Table 11: Imbalance prices applied in the Netherlands (combination of single and dual pricing systems)

		System regulation state		
		-1	+1	2
BRP imbalance	Long	$+MP_{up}$	$+MP_{dw}$	$+MP_{dw}$
	Short	$-MP_{up}$	$-MP_{dw}$	$-MP_{up}$

Therefore, apart from the recommendation for short imbalance settlement periods, ***it is recommended that, whenever the system imbalance cannot be anticipated (i.e. both upward and downward reserves are activated within a settlement period), a dual imbalance pricing system based on the price of activated reserves is implemented.***

5.3.3 Global coherence among market designs implemented

Efficiency in a certain market (or process) also depends on the global coherence among arrangements related to this market and those of markets/processes influencing the market in question. In the case of electricity balancing, the congestion management process and the intraday market may have a significant impact on balancing actions taken by the TSO.

Intraday trading versus preventive balancing actions

Intraday and balancing markets are closely related since the more (or less) BRPs adjust their schedules through the former, the less (or more) balancing actions will be needed in real time. According to ACER (2014), ***only imbalances occurring after the closure of the intraday market should be balanced by TSOs within the balancing market timeframe***. This can be explained by the fact that preventive balancing actions may compromise liquidity in the intraday market (by moving bids from this market to balancing markets) and, at the same time, increase balancing costs (which could have been minimized through intraday trading).

For this reason, ACER recommends that a higher focus should be put on decreasing the needs for TSOs to balance the system by imposing correct incentives and providing adequate and timely information to BRPs to balance themselves during the intraday timeframe and as close as possible to real time. In this line, the FG EB establishes that BSPs must be allowed to place and/or update their bids as close to real time as possible and at least up to one hour before real time. The activation of balancing bids before the corresponding balancing energy gate closure time should only be allowed in alert state or emergency state, when such activations help alleviating the severity of these system states (ACER, 2015).

Congestion management and balancing actions

While the NC EB emphasizes the right of TSOs to activate balancing energy bids for ensuring operational security and, consequently, for congestion management purposes, it establishes that ***bids activated for purposes other than balancing must not determine imbalance volumes and/or prices***.

Despite this, In Spain, the real time congestion management process generates imbalances, which affect the activation of balancing energy bids and, consequently, imbalance prices. This can be explained by the fact that, in real time, there is no process to balance generation and demand after the TSO has redispatched generation to deal with congestions. Notice that in the day-ahead timeframe bids from (constrained-off) generators to reduce (or stop) production are used to solve network constraints and bids from (constrained-on) out-of-merit units to increase (or start) production and balance demand and generation. In this case, no imbalance is generated (Fernandes et al., 2015).

The consequence of imbalances not caused (and covered) by BRPs is that imbalance prices are most likely distorted, especially under a single pricing system. Table 12 provides an example of how imbalances not covered by BRPs interfere with the amount of balancing energy activated (E_{bal}) to balance the system overall imbalance. It can be observed in the table that imbalances of BRP_1 and BRP_2 are the same for settlement periods 1, 3, 5 and 7 and for periods 2, 4, 6 and 8. Over settlement periods 1 and 2 the amount of activated balancing energy is not affected by imbalances not covered by BRPs; over settlement periods 3 and 4, imbalances not covered by BRPs reduce the need of downward and upward balancing energy, respectively; over settlement periods 5 and 6, imbalances not covered by BRPs increase the need of downward and upward balancing energy, respectively; finally, over settlement periods 7 and 8, imbalances not covered by BRPs not only modify the amount of activated balancing energy but they also change the system overall imbalance direction.

Table 12: Interference of imbalances not covered by BRPs with the system overall imbalance

	Imbalance BRP_1	Imbalance BRP_2	Imbalances not covered by BRPs	E_{bal}
1	400	−200	0	−200
2	−400	200	0	200
3	400	−200	−100	−100
4	−400	200	100	100
5	400	−200	100	−300
6	−400	200	−100	300
7	400	−200	−300	100
8	−400	200	−300	−100

Table 13: Balancing energy bid curves

Upward E_{bal} (MWh)	MP_{up} (€/MWh)	Downward E_{bal} (MWh)	MP_{dw} (€/MWh)
100	55	100	45
200	60	200	40
300	65	300	35

Imbalance prices corresponding to settlement periods 3, 4, 5 and 6 may be distorted if less expensive (cases 3 and 4) or more expensive (cases 5 and 6) balancing energy bids are activated due to imbalances not covered by BRPs. Imbalance prices corresponding to periods 7 and 8 will always be distorted since the direction of the system overall imbalance is changed. Table 13 presents typical bid curves for upward and downward balancing energy, which are used in Example 3 to calculate imbalance prices corresponding to imbalances presented in Table 9. For simplification purposes, it is assumed that single imbalance pricing is applied.

Table 14 presents imbalance prices (P_{dev}) corresponding to imbalances and balancing energy prices presented in Table 12 and Table 13, respectively, the settlement of BRPs and balancing energy and the net income resulting from the settlement. It can be observed in the table that when all imbalances are covered by BRPs, the resulting settlement net income is zero (assuming that single pricing is applied). However, if imbalances not covered by BRPs are different from zero, imbalance prices deviate from cost-reflective prices; as a consequence, the net income resulting from the settlement of imbalances and balancing energy is also different from zero.

Table 14: Settlement of balancing energy and imbalances applying single imbalance pricing and net income resulting from the settlement

	P_{dev}	Settlement BRP_1	Settlement BRP_2	Settlement of E_{bal}	TSO net income
1	40	$400 \times 40 = 16{,}000$	$-200 \times 40 = -8{,}000$	$-200 \times 40 = -8{,}000$	0
2	60	$-400 \times 60 = -24{,}000$	$200 \times 60 = 12{,}000$	$200 \times 60 = 12{,}000$	0
3	45	$400 \times 45 = 18{,}000$	$-200 \times 45 = -9{,}000$	$-100 \times 45 = -4{,}500$	$-4{,}500$
4	55	$-400 \times 55 = -22{,}000$	$200 \times 55 = 11{,}000$	$100 \times 55 = 5{,}500$	5,500
5	35	$400 \times 35 = 14{,}000$	$-200 \times 35 = -7{,}000$	$-300 \times 35 = -10{,}500$	3,500
6	65	$-400 \times 65 = -26{,}000$	$200 \times 65 = 13{,}000$	$300 \times 65 = 19{,}500$	$-6{,}500$
7	60	$400 \times 60 = 24{,}000$	$-200 \times 60 = -12{,}000$	$100 \times 60 = 6{,}000$	$-18{,}000$
8	40	$-400 \times 40 = -16{,}000$	$200 \times 40 = 8{,}000$	$-100 \times 40 = -4{,}000$	12,000

Imbalances not covered by BRPs may not only affect cost-reflectiveness of imbalance prices but also distort these prices. For instance, imbalance prices of settlement periods 7 and 8 are inverted in respect with periods 1 and 2. Under a context in which passive balancing is incentivized and assuming that the day-ahead market price is 50€/MWh, a single pricing system may lead BRPs to increase production in period 7 and decrease production in period 8, increasing the system imbalance in both cases.

5.3.4 Conclusions

Each of the options analyzed in this section is not a full blueprint of the organization of balancing markets. Instead, options are concerned with specific aspects of the functioning of these markets. Then, as a summary of the analysis carried out, Table 15 provides a clear indication of which is the most appropriate option regarding a set of features of market mechanisms for the provision of balancing services; pricing schemes applied to BRP; and coherence of the design of the balancing market with that of other markets or system and market operation actions taken at local and regional level.

Table 15: Summary of the assessment of balancing arrangements

Competition among BSPs			
Procurement of balancing capacity and balancing energy products	Joint		Separated
	Poor		Good
Procurement of upward and downward balancing capacity products	Joint		Separated
	Poor		Good
Existence of technology-specific products	Yes		No
	Poor		Good
Minimum bid size	Large (> 5MW)	Medium (1MW-5MW)	Small (≤1 MW)
	Poor	Poor to fair	Good
Pricing of balancing products	Pay-as-bid		Marginal
	Poor to fair		Good
Adequate incentives on BRPs			
Imbalance pricing system	Dual	Single	Combined
	Poor to fair	Fair to good	Good
Settlement period	Long (1 hour)	Average (30 min.)	Short (15 min.)
	Poor	Fair	Good
Efficiency in balancing actions			
Balancing & intraday trading (ID)	Preventive balancing actions		All balancing actions after ID
	Poor		Good
Balancing & congestion management (CM)	CM affects imbalances		CM is treated separately
	Poor		Good

6 Short term effects of the RES support schemes

This section is aimed for describing the analysis carried out to determine which support schemes to RES generation, or ad-hoc schemes developed for the integration of RES generation in markets, are the most promising.

Schemes are assessed from the point of view of their effects on the functioning of the system in the short term, since they may have an impact on the bids by agents in short term markets.

First, options for RES support are provided and described. Then, assessment criteria and the assessment of options itself are discussed. Lastly, most promising options overall are identified.

6.1 Options for the provision of RES support

This section provides a description of the most representative options that can be considered for the support of RES generation. Together with options, the main features of them are provided. These features include:

- The level of stability of RES revenues (price earned by the RES energy producer);
- the level of correlation of RES prices with short term market ones (reflecting marginal costs);
- whether prices earned by RES generation are computed in a market process or are, instead, administratively determined;
- the level of technology targeting, or adaptation of prices earned by RES to each technology (pre-allocation of a quantity to each technology);
- the level of efficiency in the use of public funds (technology specific subsidies may limit public funds devoted to support these technologies);
- and the level of centralization of prices earned by RES generation.

Providing or not priority of dispatch to RES generation does not depend on the support scheme applied. Therefore, support options are not characterized here according to whether they provide priority in the dispatch. In Europe, RES generation should have priority of dispatch according to regulation, see (European Commission, 2009). However, this should be made compatible with the requirement that “measures are put in place to ensure that generators have no incentive to generate electricity under negative prices”, see .(European Commission, 2014).

Next, for each option, a brief description of this support option is provided before describing its features.

A word of caution must be given at this point. The analysis of support options here undertaken must be limited in scope necessarily. Thus, while part of the support options here described and analysed below are based on the organization of auctions, the desirable features of these auctions are not part of the discussion in this section. It shall be assumed, from now on, that the potential of any RES support option based on the use of auctions is exploited to its full extent. In other words, auctions considered in support schemes here assessed are deemed to be designed in the most efficient way possible, and the assessment made of these schemes corresponds to this assumption. Not designing properly an auction would have a significant negative impact on the performance of the support scheme based on the former.

6.1.1 Long term clean capacity auctions

This is a system of long term generation capacity auctions, whereby support to a predefined amount of RES generation capacity of a certain technology to be installed (being the amount decided by authorities and the technology that, or those, that need to be supported to get mature) results from bids accepted in the auction. The marginal capacity bid accepted would be setting the price paid for each unit of generation capacity installed.

Level of stability of RES revenues

Revenues from the long term capacity auction only refer to complementary revenues required by RES promoters to decide to install new generation. Part of the revenues of RES generation would be earned in the rest of markets. Thus, the stability of revenues is medium.

Level of correlation of RES prices with short term market ones (reflecting marginal costs)

Short term revenues of RES operators fully coincide with those earned in short term markets, since revenues in the long term auction are predefined and should not be altered by operation decisions (only depend on the amount of capacity installed, though they may possibly evolve over time in a predetermined way). Thus, short term prices earned by RES are fully reflective of short term marginal supply costs.

Are prices earned by RES generation computed in a market process? If not, are they determined administratively?

Yes, they are, both in the long and the short term.

Level of technology targeting

Long term capacity auctions are normally called for specific technologies or for several of them to compete.

Level of efficiency in the use of public funds

Technology targeting increases the efficiency in the use of funds. Besides, being support provided through a market process, competition pressures drive support requested down. But uncertainty about market revenues in the short term may increase the cost of financing of investments, and therefore, increase support requested.

The level of funds transferred to RES generation through long term auctions and other markets may be high. Normally, these would not come from the public budget, but they potentially could.

Level of centralization of the process of computation of prices earned by RES generation

Prices earned by RES generation (also those corresponding to support) are computed centrally in an auction, not in a decentralized manner through bilateral trade. These auctions may be national or European wide.

6.1.2 Long term clean energy auctions

Remuneration conditions affecting the compulsory supply of a certain block of clean energy (predefined amount of it) are set through an auction process taking place in the long term.

Level of stability of RES revenues

Medium level of stability. Prices earned by RES generation for predefined amounts of the clean energy they produce are largely defined in the long term. The equivalent price earned by RES generation for this amount of electric energy produced may not be fully fixed (depending on whether the full price, a premium, or a contract for difference (CFD) with respect to some reference price level is set in the auction). The amount of power produced that is not covered by the contract is deemed to be remunerated according to conventional energy prices.

Level of correlation of RES prices with short term market ones (reflecting marginal costs)

Variable, depending on whether the full price (no correlation), a premium (medium level of correlation), or a CFD with respect to some reference price level (low level of correlation) is set in the auction.

Are prices earned by RES generation computed in a market process? If not, are they determined administratively?

Yes, they are.

Level of technology targeting

Auctions may be specific to a certain technology or addressed to all mature clean technologies in the system.

Level of efficiency in the use of public funds

Normally, funds provided to RES generation are collected from tariffs paid by consumers, though they could come from the public budget. The overall level of funds transferred to RES generation depends on whether auctions address specific technologies or all clean ones.

Level of centralization of prices earned by RES generation

Prices are computed through centralized auctions organized at system level (should probably take place for all the European system jointly).

6.1.3 Net metering of demand and generation per network user to compute regulated charges

Net power production and demand over certain periods of time are netted out in order to compute the level of regulated charges paid by the corresponding network user. Thus, a sort of subsidy can be deemed to be applied to the latter.

Level of stability of RES revenues

Low level of stability.

Level of correlation of RES prices with short term market ones (reflecting marginal costs)

Energy prices earned are fully coupled with energy short term market prices.

Are prices earned by RES generation computed in a market process? If not, are they determined administratively?

Yes, energy prices are. Only regulated charges are affected by this.

Level of technology targeting

No technology targeting is normally taking place.

Level of efficiency in the use of public funds

Level of use of public funds is limited or null. Funds indirectly paid (subsidy) to RES operators are provided by the rest of network users (conventional generators and consumers).

Level of centralization of prices earned by RES generation

Energy prices earned by RES generation normally result from centralized (short or long term) markets. Subsidies are decided by administrative authorities in the system.

6.1.4 Feed-in-Tariffs (FIT) both regulated and resulting from an auction

Features of both FIT schemes are described jointly in Table 16. This is due to the fact that these two schemes have several features in common.

Table 16: Features of main FIT RES support schemes

	FIT with Regulated Prices	**FIT with auction**
Description	Administratively set tariff for every MWh produced over a given period.	Tariff is provided for a given period, the level is the result of an auction taking place in the long term.
Level of stability of RES revenues	High level of stability of prices.	
Level of correlation of RES prices with short term market ones (reflecting marginal costs)	No coordination of price earned by RES with short term market ones.	
Are prices earned by RES generation computed in a market process? If not, are they determined administratively?	No.	Yes.
Level of technology targeting	FIT are normally specific to a certain technology.	
Level of efficiency in the use of public funds	Normally, very large amounts of funds are transferred to RES technologies through this scheme (no tech. targeting). However, funds paid may or may not come from the public budget (normally paid by electricity consumers).	
Level of centralization of prices earned by RES generation	Prices earned by RES generation are centrally computed by administrative authorities.	Prices earned by RES generation are centrally computed in an auction.

6.1.5 Feed-in-Premiums (FIP) both regulated and resulting from an auction, and both unbundled and with an overall price cap and floor

Features of all FIP schemes are described jointly in Table 17 .[17] This is due to the fact that these four schemes have several features in common.

[17] Within Market4RES deliverables D4.1 and D4.2 [insert link when published], this support scheme is referred to as Price Premium (PP).

Table 17: Features of main FIP RES support schemes

	FIP regulated with no price cap and floor	FIP resulting from an auction with no price cap and floor	FIP regulated with overall price cap and floor	FIP resulting from an auction with overall price cap and floor
Description	Administratively set premium on top of market price for every MWh produced over the given period.	Premium on top of market price is set for a given period, but the level of the premium results from an auction.	Administratively set premium on top of market price for every MWh produced over the given period. There is a maximum and a minimum level for the overall price resulting from adding up market price and premium.	Premium on top of market price is set for a given period, but the level of the premium results from an auction. There is a maximum and a minimum level for the overall price resulting from adding up market price and premium.
Level of stability of RES revenues	Revenues volatility associated with energy market prices and the volume of energy served.		Higher revenue stability than non-constrained FIPs, but lower than that with FIT. Volatility also associated with energy market prices and the volume of energy served. However, this is limited to the range between the price cap and floor set.	
Level of correlation of RES prices with short term market ones (reflecting marginal costs)	Prices earned by RES generation are correlated with energy market prices.		Prices earned by RES generation are correlated with energy market prices, though correlation is lower than that under non-constrained FIPs, because this correlation does not exist for very high and very low market prices.	
Are prices earned by RES generation computed in a market process? If not, are they determined administratively?	Yes, as far as the energy market component is concerned. The premium part of revenues is administratively set.	Yes.	Yes, as far as the energy market component is concerned, and as long as prices keep within the range between cap and floor. The premium part of revenues is administratively set.	Yes, as long as prices keep within range between cap and floor.
Level of technology targeting	FIP are normally specific to a certain technology.		FIP, caps and floors, are normally specific to a certain technology.	
Level of efficiency in the use of public funds	A separate premium may be set for each technology supported. Hence, it is possible to tune it, to some limited extent, to the level of revenues required by this technology, thus minimizing funds devoted to supporting RES technologies. In any case, these may probably not come from the public budget (normally paid by electricity consumers), though they could. There is a risk of having RES generation earning prices that are very high or low associated with market prices being very high or low. Some waste of public funds may occur then.		A separate premium, as well as price cap and floor, may be set for each technology supported. Thus, it is possible to tune it to the level of revenues required by this technology, thus minimizing funds devoted to supporting RES technologies. In any case, these may probably not come from the public budget (normally paid by electricity consumers), though they could. More control than FIPs without price caps over final prices earned by RES generation being supported.	

	FIP regulated with no price cap and floor	FIP resulting from an auction with no price cap and floor	FIP regulated with overall price cap and floor	FIP resulting from an auction with overall price cap and floor
	Level of premiums is efficient to the extent authorities are able to accurately determine the level of costs of each technology and the level of prices.	Level of premium is efficient to the extent that there is a high level of competition in the auction where these premiums are determined.	Level of premiums is efficient to the extent authorities are able to accurately determine the level of costs of each technology and the level of prices.	Level of premium is efficient to the extent that there is a high level of competition in the auction where these premiums are determined.
Level of centralization of prices earned by RES generation	Premiums earned by RES generation (of each technology) are computed centrally (all power plants of the same technology get the same premium). However, premiums may be the same across the whole system, or they may be differentiated according to the area where they are applied. Besides, the market price component may vary across zones or nodes, if some geographical differentiation of prices exists.		Premiums earned by RES generation (of each technology), as well as final prices caps and floors, are computed centrally (all power plants of the same technology get the same premium). However, premiums caps and floors may be the same across the whole system, or they may be differentiated according to the area where they are applied. Besides, the market price component may vary across zones or nodes, if some geographical differentiation of prices exists.	

6.1.6 Certificate Schemes with Quota

Introduction of a quota for several years per renewable technology. Electricity suppliers would be either obliged to produce a certain volume of green energy, or to buy an equivalent volume of “green” certificates corresponding to electricity produced by RES producers.

Level of stability of RES revenues

High Volatility of RES revenues, since both the short term energy market price and the certificate price could exhibit some volatility. Volatility of the certificate price depends on when RES producers sell these (if in the long term or in the short term).

Level of correlation of RES prices with short term market ones (reflecting marginal costs)

Prices earned by RES generation are correlated with energy and certificate market prices. Correlation is higher over a certain period of time if certificates have been sold in the long term for this period. Otherwise, correlation of final prices with energy market prices is lower.

Are prices earned by RES generation computed in a market process? If not, are they determined administratively?

Yes.

Level of technology targeting

Quotas are normally common to all technologies. Thus, no technology targeting, in principle. However, exceptions may exist to this rule in some systems, where quotas are specific to certain technologies.

Level of efficiency in the use of public funds

No funds involved in the direct support of RES energy production, but an increase in electricity prices is expected. Funds can be devoted to other goals, like infrastructure development.

Level of centralization of prices earned by RES generation

Energy prices are centrally cleared in energy markets. However, a separate energy price may be computed for each area according to system constraints. Certificate prices are not computed centrally. However, if efficiently negotiated, certificate prices should be common for all generators within each area, if a separate quota is set for each area, or they should be common to the whole system, if a single quota is defined for all the system.

6.1.7 No support (conventional market remuneration)

No support mechanism. RES producers would sell at the best price offered in the market.

Level of stability of RES revenues

High volatility of revenues. When, large amounts of RES generation are available, prices are expected to decrease substantially. Then, average prices earned by RES generation are expected to be low.

Level of correlation of RES prices with short term market ones (reflecting marginal costs)

Prices earned by RES generation are the same as those earned by any other type of generator producing power at the same time (with a similar profile). 100% correlation with energy market prices.

Are prices earned by RES generation computed in a market process? If not, are they determined administratively?

Yes.

Level of technology targeting

No support to RES generation. Therefore, no targeting.

Level of efficiency in the use of public funds

No funds devoted to the direct support of RES energy production in the short term to promote the deployment of this generation.

Level of centralization of prices earned by RES generation

Prices earned by RES generation are centrally computed in organized markets (day-ahead ones). They may exhibit geographical differentiation according to local constraints set.

6.1.8 Support conditioned to the provision of grid support services

In this case, support to RES generation, which tend to be of a FIP or FIT type, is largely contingent on the provision of voltage support service by this RES generation. RES generation not providing voltage support earns some basic support which is much lower than that earned by RES generation providing voltage support. As far as authors are aware of, this scheme has only been implemented in Germany.

Level of stability of RES revenues

The stability of revenues of RES generation from support depends on the particular scheme adopted (FIT, FIP, others). Some stability for FIT or FIP.

Level of correlation of RES prices with short term market ones (reflecting marginal costs)

The correlation between RES short term revenues and market prices depends on the particular scheme adopted (FIT, FIP, others). Low correlation with FITs, higher with FIP.

Are prices earned by RES generation computed in a market process? If not, are they determined administratively?

Prices earned by RES generation may or may not be computed in a market process (could be determined administratively or through an auction).

Level of technology targeting

Targeting of technologies is common if FITs or FIPs are applied in combination with the requirement to provide voltage support.

Level of efficiency in the use of public funds

Funds to be transferred to RES generation through support may be high for FITs or FIPs, but normally do not come from the public budget (included in electricity tariffs), though they could.

Level of centralization of prices earned by RES generation

Support payments to RES generation may be centrally computed either by central authorities (if FITs or FIPs are administratively determined) or in the market (if they are determined in an auction).

6.2 Assessment criteria

In the following paragraphs, each of the criteria used to assess the short term effects, in markets and elsewhere, of RES support schemes is described. Criteria are organized in groups, when appropriate. An overall classification of assessment criteria can be carried out following the same pattern as that presented in D3.1 for the criteria applied to assess the long term effects of RES support options. It will not be repeated here. A description of groups of criteria is provided when this is believed necessary because these groups have not been analysed before.

6.2.1 Economic Efficiency

These criteria are concerned with the impact that support schemes for RES generation may have on the short-term economic efficiency of system functioning, i.e. on the economic efficiency of operational decisions by market agents and Network and System Operators.

(Marginal) cost reflectivity

Within the short term, and acknowledging this is already a simplification of reality, we may define an efficiency criterion related to the extent to which marginal revenues of RES operators reflect the marginal short term value of this production, or marginal short term supply cost in the system. There are a range of situations in this regard: from that where marginal revenues of RES generators are fully decoupled from the short term marginal system supply cost (FITs for instance), to the situation where these marginal revenues are 100% coincident with short term marginal supply costs (full market integration) because markets for RES result in fixed payments that do not depend on the level of power production by this generation.

Cost causality

Cost causality exists if the remuneration received by RES producers in short term markets is paid by those agents which are not contributing to decarbonisation or RES objectives. This should result in more efficient – regarding the objectives - short term decisions made by, for example, producers, consumers or suppliers. An example of this are certificate schemes such as Renewable Portfolio Schemes or ROC/Green Certificate. Other support schemes may not have direct implications on who pays the costs of RES energy supply.

Liquidity

Markets should in theory not exhibit liquidity problems. They should be as liquid as possible, thus enhancing competition. RES support schemes should not decrease the liquidity in short term-markets reducing the efficiency of the operation of the system, like Power Purchase Agreements (PPAs) or over-the-counter (OTC) types of contracts that reduce the amount of power transacted in short term markets. The reduction of liquidity brought about by these instruments shall be weighed against their benefits.

Global coherence (spatial and temporal)

Support payments could be computed in a harmonized way across areas and time. This would lead to the harmonization of unit support payments received by RES generation across the whole system and over the whole year. This is coherent with the fact that emissions or RES targets are defined over an overall region (country or continent), and time frame. In other words, the contribution to achieving a target of a specific energy unit of RES is the same no matter the localization of the generator or the time at which it has been produced within the defined region and timeframe. Both the way support payments are computed and the level of support payments for each RES technology could be harmonized, but not final prices earned by RES generation in all areas of the system and times of the year.

Besides, remuneration of RES generation should allow competition to take place among mature RES technologies and with conventional technologies to the extent that the context allow the former to compete with the latter (in compliance with the transparency criterion).

Finally, the remuneration of RES generation should not, if possible, interfere with short term signals provided by short-term markets (in compliance with the overall efficiency criteria).

The previous points are related to the fact that prices earned by RES generation should not interfere with efficient short term operation signals (prices). In other words, support payments should not prevent mature RES generation and other market agents from making efficient short term decisions.

6.2.2 Robustness

The support mechanism implemented should as far as possible and at the same time ensure the short term economic efficiency and comply with system security, emission and RES targets. This could lead to conditions for the deployment of RES generation which are not the ones initially assumed. There is a multiplicity of factors affecting the amount of RES generation installed. Changes to the level of these factors leading to an unanticipated amount of RES generation in the system should not cause large economic efficiency losses in the dispatch with respect to the reference dispatch where all generation production is scheduled according to a purely economic merit order.

6.2.3 Implementability

Compatibility with existing regulation/principles and markets

New (centralized) RES energy pricing schemes developed may face the opposition of parties willing to stick to already existing ones. Besides, the system of prices applied should, to the extent possible, not be against principles widely implemented in the IEM or European legislation, like marginal supply cost reflectivity.

Relevance of barriers faced by RES operators for their participation in markets

Unit size and players experience are also factors which have to be taken into account when considering the implementability of a specific scheme. Market access rules can prevent and make the implementation of a specific market based support policy difficult. The implementation of a specific mechanism could require further adaption of market rules and/or the emergence of new actors facilitating the trading or valorization of RES electricity.

Level of use of funds from the public (State/local government) budget

In some systems, mechanisms related to the adoption of clean technologies have been funded from the public budget. Under this criterion, the amount of funds provided by public authorities that are used to support RES generation should be as low as possible, since these public funds are scarce. The use of large amounts of public funds by a support mechanism may condition its acceptance by authorities.

Cost efficiency

The overall amount of funds provided to RES generation in the form of support payments should be the smallest one possible that is compatible with achieving the desired level of deployment of this generation.

6.2.4 Fairness: stability of support payments

The scheme of support payments applied should not involve changes in the revenues of RES generators that cannot be anticipated or reasonably managed by them. Importantly, retroactive changes should be avoided as they shatter investors' confidence in any investments in the power generation fleet in general. Rules applied and input factors considered for the determination of support payments should be clearly stated and stable, i.e. should not change over time. This, besides reducing the effectiveness of the scheme to drive the deployment of new RES generation, could be considered unfair.

6.3 Assessment of options for RES support schemes

In the following, the grades **Very good**, **Good**, **Fair**, and **Poor** are applied for each combination of RES support scheme and criterion. A "**+**" sign indicates a grade between that assigned and the next better grade (similarly a "**-**" sign indicates a grade between that assigned and the next lower grade).

Note also that a full evaluation of an option by no means is the average of the grades obtained for all criteria, as a sufficiently poor evaluation in one criterion in principle can disqualify this scheme entirely. Moreover, some criteria may be more important than others.

6.3.1 Efficiency

Marginal cost reflectivity

Assuming that the **Net metering of demand and generation per network user for the computation of regulated charges** is applied when regulated charges depend on energy produced or consumed. Otherwise netting power production and consumption would not provide any support.

Market players are exposed to market prices that are not affected by tariffs or premiums, which may be deemed to efficiently reflect marginal supply costs. However, this scheme may create some distortions in the bidding behavior of RES generators that are located together with some demand (or vice-versa) and billed as a single network user. This support scheme would result in regulated charges paid by these RES generators (or the consumers associated with them) changing with the level of power production of this RES generation, and with the level of consumption of the associated demand. Then, these agents shall internalize in their bids the impact of power produced or consumed by them on regulated charges. However, this is inefficient, since most regulated charges do not depend on short term operation decisions. Consequently, bids in short term energy markets by this group of agents shall differ from pure marginal system costs associated with their level of power production or consumption. In other words, some distortion will take place in the bidding behavior of this group of agents. As in the case of FIPs, support provided to the development of RES generation to be able to provide extra clean energy in the long term is being associated with the decision to provide energy (and clean energy as well) in the short term, which is not efficient. Then, the performance of this option is Fair.

Under both **FIT with Regulated Prices and FIT resulting from an auction**, the revenue received by the RES generator is unrelated to the short term market prices. Hence the marginal cost is irrelevant as a short term operation signal. The generator will simply generate unless the short-term marginal cost is above the FIT. Through selling into the market, the RES generator would enter trades at marginal costs (assumed zero for wind, solar) minus the tariff. Orders would be placed into the market below zero. **FIT resulting from an auction** are only a slight improvement over the FIT with regulated prices, since there is some attempt of cost/price discovery for the tariff level, which is nevertheless a long term signal, not a short term one. If the auction forces the subsidies to low levels it may fail to achieve the desired results to attract long-term investment. i.e. fail to cover total costs. Then, the performance of both schemes of FITs is Poor.

Under **FIP regulated with no price cap and floor**, there shall be assumed that separate premiums are set for each technology or group of technologies. Assuming low marginal costs (e.g. zero) the market party would be rational to bid into the market at negative prices. The market prices could be heavily influenced by the FIP level e.g. the occurrence of negative clearing prices down to the level of the premium. The market parties will act in accordance to its marginal cost and the premium level (i.e. it will generate only if the market clearing price is above the marginal cost minus premium), and would be more sensitive to its costs if the premium is set at a relatively low level. In situations where the premium is large, the generator's position in the generation stack could change, meaning that it will always be dispatched first, thus reducing the strength of the signal of marginal cost. Given that different premiums are set for different technologies, the merit order of RES technologies may be altered. Then, the performance of this option is Fair. It is not expected that the Marginal Cost Price (MCP) reflectivity for **FIP resulting from an auction with no price cap and floor** is different from that for FIP regulated with no price cap and floor. It is a question of the level and distribution of the subsidy.

FIP regulated with overall price cap and floor is between the FIP without a cap and floor and a FIT. The RES generator has some incentive to bid and produce in accordance with market conditions if the market price is within certain boundaries. In the situation where market clearing price is below the level of the floor, the market player is incentivized to produce even when it may not be efficient from a system welfare point of view. Price caps and floors further distort marginal price signals when they are binding (as the premium acts as a tariff). Given that different premiums are set for different technologies, the merit order of RES technologies may be altered. Then, the performance of this option is Fair-. It is not expected that the MCP reflectivity for **FIP resulting from an auction with overall price cap and floor** is different from that of FIP regulated with overall price cap and floor. It is a question of the level and distribution of the subsidy.

It is assumed that when applying **Certificate Schemes with Quota**, revenues from certificates are associated with the amount of energy sold in the energy market. Unlike signals resulting from the ETS scheme, the certificate price, which is not varying from an operation hour to another, does not reflect the system costs that would have been caused by the power production that this unit of clean energy is replacing in each hour. Then, even if applied instead of the ETS (which would probably not be the case in the IEM), the certificate price would be distorting short term signals, which should be equal to the short term marginal value of energy. The size of the distortion is proportional to the price of the certificates. Then, the performance of this option is Fair.

The marginal cost reflectivity of **Long term clean energy auctions** depends on the rules for delivering electricity and the penalties for not delivering committed energy. It is assumed here that RES generators only get the support payment if they deliver the energy as committed, and that a penalty is applied if not enough electricity is produced as committed in the auction. Then, RES generators' bids in high price hours, until reaching the amount of energy sold in the long term auction, should be set at a maximum equal to their marginal production cost less the premium resulting from the auction, if FIPs result from this auction, or equal to large enough negative prices to be dispatched if FITs, or CfDs, result from the auction. However, this should result in very limited distortion to market results if RES generation is infra-marginal (would not affect the resulting prices in the short term energy market). On the other hand, in low price hours, where bids by RES generation being supported may be affecting the marginal market price, these generators should not be earning any support payment in order to bid their marginal production costs and not to distort the market price and generation dispatch. If energy produced by these generators in low price hours must, or may need to be, also taken into account to reach the amount sold by them in the long term clean energy auction, these generators may probably internalize support payments received in their bids. This will distort market operation.

Additionally, predicting market conditions in each hour may be very difficult. Then, RES generators may assume low price hours are going to be high price ones and internalize support payments in their bids in hours where prices are very low and RES generation is setting the market price. Then, they would be distorting price signals. In these hours, distortions created by FITs may probably be larger than those created by FIPs.

Overall, one may conclude that distortions created in short term signals by the use of long term clean energy auction may be lower than under FITs, or FIPs, but will most probably exist. Distortions will be small if the amount of clean energy production sold by RES plants in the long term auction is small compared to the level of production of these plants in the absence of support (if the former is for sure smaller than the latter). On the other hand, distortion will be significantly larger if energy sold in the long term auction is, or may be, larger than their economic level of production (that resulting from free competition with other technologies). In the latter case, distortions may probably increase if generators are not able to identify beforehand which hours are going to be high price ones.

However, one may assume that RES investors will behave rationally trying to maximize their profits. Then, they shall build the minimum amount of RES generation needed to produce the amount of energy committed in the long term auction. In this way, they shall receive the maximum amount of support payments possible while minimizing the cost of investments, which are supposed to clearly exceed market revenues for technologies that need to be supported. Given these assumptions, support based on long term clean energy auctions is supposed to condition the operation decisions by agents similarly to how the corresponding short term energy payments would do. It would be Fair for **FIPs**, and Poor for **CfDs** or **FITs**.

Under **Long term clean capacity auctions** RES Capacity installation is supported without interfering efficient short term market prices. Support received by RES generators does not depend on their operation decisions. Hence, they will bid the energy produced at short-term marginal cost into the market. The performance of this option is Very Good.

When **No support (conventional market remuneration)** is provided, under normal trading conditions, market parties have to bid/generate taking into account marginal costs. Then, the performance of this option is Very Good.

Under **Support payments that are subject to provision of voltage support**, RES generators providing voltage support would be earning energy prices that are more or less distorted depending on the support scheme implemented. RES generators not providing voltage support would be basically subject to efficient marginal prices. Thus, this scheme is improving a bit the MCP reflectivity of prices earned by RES generation as a whole, but not that of prices earned by RES generation being supported. Then, the performance of this option is Fair+ for **FIPs**, and Poor+ for **FITs**.

Liquidity

Any solution that promotes local netting of power production and consumption, like **Net metering of demand and generation per network user for computation of regulated charges**, will decrease liquidity in markets, since neither supply nor demand needs to enter the market unless the RES generation does not deliver power. In that situation the liquidity would not necessarily increase. However, decreases in market liquidity (and transparency) could be lowered if both generation and demand are obliged to submit market bids (i.e. on an auction). Then, the performance of this option, generally, is Poor.

Under **FIT computed as Regulated Prices and FIT resulting from an auction**, RES generation has no need to trade as revenue is unrelated to energy prices. Generators would spill directly into the grid due to priority dispatch. Then, the performance of these options is Poor.

When **FIP regulated with no price cap and floor** are implemented, market parties need to participate in the market. The volume bid would be the same as without subsidy. Only the bid prices will differ. Then, the performance of this option is Good. It is not expected that the liquidity in **FIP resulting from an auction with no price cap and floor** is different from that for FIP regulated with no price cap and floor. It is a question of level and distribution of the subsidy.

Under **FIP regulated with overall price cap and floor**, RES generation whose variable power production cost, less the FIP, lie within the boundaries of the cap and floor should participate in the market (Good). However, this will not occur for RES whose production cost less of the FIP is below the floor (Poor). If there is a specific market referenced for the cap and floor, then that market could see an increase in its liquidity as it provides the perfect hedge for the generation (Good). Then, the performance of this option is **Fair**. It is not expected that the liquidity of **FIP resulting from an auction with overall price cap and floor** is different from that for FIP regulated with a price cap and floor. It is a question of level and distribution of the subsidy.

When **Certificate Schemes with Quota** are applied, all market parties would participate in the market. Given a separation of the certificate and the energy markets, this creates a potential for the plant to move in and out of the money more frequently. This would promote liquidity as generators would be able to profit through selling and buying back the electricity and certificates as the prices move. If the certificate's price was dynamic then this would create additional churn (liquidity) in the market beyond that which would have been seen just through changes in the electricity price. Then, the performance of this option is **Good**.

Under **Long term clean energy auctions**, if the support mechanisms allow the RES generation plant in and out of the money, then liquidity will improve in the clean energy market – as described in the other examples. For example, in the example of the CfD, it can benefit liquidity in the referenced market(s) as it allows market participants a perfect hedge against prices. However, as any other scheme supporting the use of RES generation, this mechanism will not necessarily improve liquidity across all trading venues. It could have a detrimental impact on other generation assets which are moved up the generation stack and less likely to be at the margin. In this circumstance they will not "churn" their volume in the market reducing liquidity. Then, the performance of this option is **Good**.

When **Long term clean capacity auctions** are applied, all RES would have to participate in the market and bid according to marginal cost. Then, the performance of this option is **Very Good**. The same occurs when **No support (conventional market remuneration)** is applied.

Under **Support payments that are subject to provision of voltage support**, RES generators are encouraged to provide voltage support. Liquidity will depend on the specific support scheme in place subject to the condition of providing voltage support. If FIPs are applied, RES generators would bid both if providing voltage support and if not. Then, liquidity would be unaffected by the application of the voltage support condition. If FITs are applied, this condition would improve liquidity a bit, since RES generators not providing voltage support would bid in the market, unlike generators when no obligation to provide voltage support exists. As providing voltage support reduces the amount of power available to be produced, less generation capacity would be available in the energy market, which should reduce (a bit) liquidity. On the other hand, liquidity in the Ancillary Services (AASS) market will generally increase. There may be some shift in liquidity from the spot market to the ancillary services market. Then, the performance of this option is <u>**Good**</u> if **FIPs** are applied, while it is worse for other alternatives. Thus, if **FITs** are applied, the performance of this scheme is <u>**Poor+**</u>.

Cost Causality

Under **FIT computed as regulated prices and resulting for an auction**, renewable energy generators receive a fixed tariff, administratively set and set through the auction, respectively, per MWh produced over a given period. These design options define the total amount of support to renewable production, but it is silent about the cost allocation. Generally, it will be each national government defining the RES targets that will decide on the cost allocation of RES production but some criteria other than cost causality might be taken into account on that decision. Then, <u>no grade</u> is attributed to this option.

Under **FIP regulated with no price cap and floor**, **FIP regulated with overall price cap and floor**, **FIP resulting from an auction with no price cap and floor, and FIP resulting from an auction with overall price cap and floor,** renewable energy generators receive a fixed premium in addition to the electricity market price per MWh produced over a given period. These design options define part of the amount of support to renewable production but it is silent about the cost allocation. Generally, it will be each national government defining the RES targets that will decide on the cost allocation of RES production Premiums. Some criteria other than cost causality might be taken into account on that decision. Though the marginal cost of energy production in each hour is being efficiently allocated to consumers, these mechanisms are not providing an answer to who is paying the EXTRA cost of RES energy. For this reason, <u>no grade</u> is attributed to them.

Under **Certificate Schemes with Quota**, Renewable energy generators receive one certificate for each unit of clean energy they produce which, by its turn, could be sold to those agents who need to certify RES based electricity generation. For that reason, we understand that 'Certificate schemes with quota' would perform very well under this assessment criterion, as the extra cost of RES energy supply is actually paid uniformly (in unit terms) by consumers, or suppliers selling power to them, which are the agents having caused the need to produce clean energy. Thus, the performance of this option is <u>**Very Good**</u>.

Under **Long term clean energy auctions**, Renewable energy generators receive a fixed price resulting from an auction for a certain block of clean energy administratively set. This design option does not define the allocation of the extra cost of RES production. For this reason, <u>no grade</u> is attributed to this option.

A similar situation exists when **Long term clean capacity auctions** are organized. No indication is provided by this support scheme on who should pay the extra cost for the system of achieving the installation of a predefined amount of RES generation capacity of a certain type. Then, <u>no grade</u> can be attributed to this design option either.

Under **Net metering of demand and generation per network user for computation of regulated charges**, consumers with onsite RES generation supported are benefiting from a cost reduction in regulated charges. Indeed, since they are reducing their energy imports from the grid they will reduce the amount of regulated charges paid to the system. These regulated charges include namely grid charges and support costs to RES and other technologies. Since this type of costs has to be recovered anyhow, meaning that the reduction in regulated charges paid by consumers netted with RES generation will imply a burden increase to all other network users paying regulated charges, which certainly include consumers, but maybe also generators. Then, assuming that consumers are the entities responsible for RES deployment, one could consider that this scheme is performing fairly (if both generators and consumers pay regulated charges) to well (if only consumers pay these charges) under the cost causality criterion. Then, the performance of this option is **Fair** or **Good**.

When **No support (conventional market remuneration)** is applied to RES generation, RES costs are not transferred to agents which did not consume RES energy. Since no support is provided consumers pay energy according to its marginal value. No extra RES costs are incurred, so no need to allocate it. For this reason no grade is attributed to this option.

Lastly, as for many other mechanisms, the fact that **Support to RES is conditioned to the provision by this generation of grid support services (voltage support)** is not providing an answer to the question of who is paying the cost of RES support. For this reason, no grade is attributed to this option.

Global Coherence (spatial and temporal)

Both FIT with regulated prices and **FIT resulting from an auction** are normally applied separately for each country/area. Then, these schemes may not provide a coherent treatment to generation in all areas. Besides, under these schemes, short term prices offered in the market by RES operators do not reflect their marginal production costs. In negative price situations, for instance, RES producers under a FIT scheme will not react to the excess production signals sent by the market. Besides, these support schemes are normally designed to support immature technologies or small-scale applications, which have difficulties to bear the price risks or transaction costs for participating in a market platform with professional traders. Consequently, this leads to RES operators not making efficient decisions in the short term. FIT of any kind are also distorting long term signals, since the resulting distribution of RES generation across areas/countries in the system is not efficient. In the case of FIT set administratively, additionally, tariffs are not set to recover the long term marginal costs of the corresponding generation. Hence, long and short term signals produced by FIT are not coherent with each other and they are not coherent either with the efficient functioning of RES generation in any time frame. Therefore, the performance of FIT is **Poor**.

FIP of any kind are normally applied separately for each country or area. Then, RES producers of the same technology from different areas may be earning different premiums, which would distort market and system operation. Therefore, short term prices offered in the market by RES operators may reflect more or less closely its marginal production costs depending on the energy market prices level and the level of the premium administratively set. In the case of negative prices, RES producers under this scheme will react to the excess production signals sent by the market but only when the negative price level surpasses the regulated premium defined. All in all, FIP create some distortion of short term signals, though smaller than under FITs. In the long term, if FIP are regulated, the level of FIPs may not be appropriately set to cover long term marginal costs of the generation whose installation is to be achieved. Besides, for any kind of FIP, the resulting distribution of RES generation across areas/countries in the system is not efficient.

Therefore, there is some distortion of long term signals as well for all FIP. Coherence between short and long term signals and the desired functioning of the system is not achieved. Then, the performance of FIP schemes is between Poor and Fair.

Certificate schemes with quota are normally applied in a coordinated manner across the whole system and are aimed at supporting mature technologies promoting competition among them. Then, this scheme is providing a coherent treatment to RES generation in all areas. Short term prices earned by RES generation under this scheme do not correspond always to the short term value for the system of the clean energy they produce. So the efficiency of short term system functioning could be improved. In the long term, the distribution of RES generation across areas/countries in the system is efficient (resulting from a centralized process), while the overall amount of RES generation deployed is centrally set, and the balance among technologies is the result of market forces if a single quota is set for all RES generation supported. So long term signals are coherent with an efficient functioning of the system. Then, the performance of this option is Good.

Long term clean energy auctions are here assumed to be organized separately (in a non-coordinated way) for each area or country. Then, this scheme is not providing a coherent treatment to RES generation in all areas. Distortions introduced by this scheme in short term operation decisions are smaller if premiums are computed in the auction than if CfDs or FITs result from it. However, as mentioned above, the two variants of the scheme produce some distortions of short term signals, which are similar to those produced by FIP and FIT, respectively. In the long term, the distribution of RES generation across areas/countries in the system is not efficient, though support in each area is supposed to cover local long term marginal costs of supported generation. Therefore, there is some distortion of long term signals. Then, the performance of this option is from Poor, if **FIT** or **CfD** result from the auction, to Fair, if **FIP** are paid.

Assuming **Long term clean capacity auctions** are organized separately for each country or area, they will not be providing a coherent treatment of RES generation across areas. Otherwise, they will not distort short term signals, non efficient long term ones, so they would be coherent with the efficient functioning of the system in both time frames. Thus, the performance of these auctions in this regard is between Good and Very Good.

As mentioned above, **Net metering for the computation of regulated charges** is deemed to be applied when regulated charges applied depend on energy produced or consumed. These charges are supposed not to be harmonized at European level and are deemed to be mainly paid by consumers in the system. Then, applying this scheme would reduce non-harmonized regulated charges paid by some consumers (those with RES) and would increase regulated charges paid by other consumers (those without RES generation). Given that demand with RES generation on-site will be paying different levels of regulated charges in different countries or areas (since this is not harmonized), support payments obtained by RES generation will vary across countries. Therefore, the treatment given to RES generation will not be coherent across areas. Given that regulated charges are energy based, support provided to RES through this scheme will affect short term operation decisions, while it should not. In other words, the application of this scheme is not coherent with the efficient operation of RES generation. Lastly, investment incentives created by this scheme are unlikely to complete the recovery of long term costs of marginal RES generation whose installation is pursued. Additionally, support to the installation of RES will not be coherent across countries. Therefore, this scheme is not coherent with the efficient development of the system. Then, the performance of this option is Poor.

Providing no support (conventional market remuneration) is coherent with treating RES generation in all areas in the same way. Under this design option, no support to RES-E generation exists and, therefore, short term prices offered in the market by RES operators will reflect their marginal production costs and no distortion of long term signals occurs. Then, the performance of this option is Very Good.

Conditioning RES support to the provision by these generators of grid services does not involve introducing any discrimination within RES generation related to its location. So this scheme is providing a coherent treatment of RES generation across areas. However, this scheme is introducing a discrimination against those generators not being able to provide voltage support regardless of the value for the system of the installed capacity of these generators (which is the feature of RES generators to be considered for computing the amount of support to be provided). Then, the performance of this option is between Poor and Fair.

6.3.2 Robustness

FIT and FIP that are regulated are centrally computed by administrative authorities, which means that the possibility for political intervention is very high. Moreover, being support payments to RES generators administratively set, they do not necessarily adapt to changes in market and system conditions, namely technology costs for FITs and both these and market prices for FIP, which change over time. Then, the amount of investments in RES generation caused by these schemes normally changes with changes in market and system conditions (RES deployment costs). In the short term, the efficiency of the energy dispatch largely depends on the relative level of support payments with respect to marginal production costs in the system, which, again, depend on market and system conditions. Applying a cap and floor to final prices earned by RES under a FIP scheme may reduce the sensitivity of long term signals produced by this support scheme with respect to market conditions, but signals will in any case be sensitive to conditions. Operation inefficiencies created by FIP with a cap shall be between those for a FIT scheme and those for FIP scheme without a cap. Then, the performance of these options is Poor.

FIT and FIP resulting from an auction, being based on a competitive market process, are less dependent on political intervention than regulated FIT and FIP. Besides, the level of FIT or FIP in each auction should adapt to existing system conditions at that time, assuming competition in the auction is large enough. Then, long term signals should be efficient despite changes occurring in system conditions. However, as for regulated FIT and FIP, the relative level of support payments compared to efficient short term signals (marginal production costs) would change when a change in system conditions occur. Thus, for FIT, if short term prices decrease, support payments will increase (final price earned by RES remains equal to FIT levels) while marginal production costs decrease, which involves that inefficiencies in the short term market will increase. Under FIP set in an auction, changes in inefficiencies resulting from changes in market and system conditions may be larger or smaller than under FIT depending on the sign of changes in prices. When a cap and a floor is set for the final price in a FIP scheme, the sensitivity of distortions in short term markets produced by RES support with respect to system conditions is going to be between that of unconstrained FIP and that of FIT. All in all, short term market inefficiencies largely depend on system conditions. Then, the performance of all these options is Fair.

Being a competitive market process organized to set support payments**, Certificate schemes with quota** offer less opportunities for political intervention than mechanisms where support payments are determined administratively. This is so, because interventions affecting the quantity target are more difficult than those affecting the level of payments. Besides, changes in system conditions should result in a change in the price of certificates being issued by RES generators. However, the particularities of this support scheme may result in some abrupt changes in the level of support payments (price of certificates), which are not good to drive RES generation investments. Thus, there is the risk that, once reached the RES target, a drop (potentially to zero) in certificate prices occurs. In order to avoid this, the RES quota set should be monitored and modified to evolve in line with the actual RES penetration level and targets defined. Then, the size of inefficiencies in long term signals should be lower than under regulated schemes but, if quotas set are not modified appropriately with the passing of time, it may be larger than under price based support mechanisms organized through auctions.

Changes in system conditions (fuel prices, RES deployment costs) may probably result in a change in support payments (the price of certificates) as well as in the level of short term energy market prices. Then, distortions introduced in short term signals by this mechanism may probably depend on system conditions. Then, the performance of this option is Fair.

As argued above for auction based FIT and FIP, being a mechanism whereby support payments are set in a market, **Long term clean energy auctions** offer less opportunities for political intervention than mechanisms where prices are determined administratively. Regarding long term signals, support payments defined in each energy auction taking place should adapt to future system conditions expected at that time. So long term signals should be adapted to changes on system conditions. The adaptability of long term signals shall depend on the frequency of long term energy auctions conducted.

Regarding the short term signals produced by this mechanism, as mentioned above, assuming a rational behavior of agents, the latter shall make operation decisions similar to those resulting from the application of FITs or FIPs, depending on which of the two kinds of payments result from long term clean energy auctions organized. Therefore, the level of distortions introduced in short term signals by these auctions shall depend on system conditions. Then, the performance of this option is Fair.

Long term clean capacity auctions cannot be easily manipulated by authorities, since auctions are a market based mechanism and quotas defined for RES considered in these auctions are difficult to manipulate. Long term signals produced by auctions should adapt to changes in system conditions so as to achieve the deployment of the desired amount of RES generation, though this would depend on the frequency of auctions conducted. Lastly, short term signals received by generators should never be conditioned by auctions, since capacity support payments resulting from these auctions do not depend on operation decisions by agents. Then, the performance of this scheme is Very Good.

If **Net metering of demand and generation per network user is applied for the computation of regulated charges**, support payments to RES could be easily manipulated by political authorities, since regulated charges, like network ones, can be easily modified by authorities. Given that regulated charges applied in combination with this scheme are expected to be made dependent on energy production/consumption by network users (system operation), changes in system conditions affecting the system operation are expected to affect the level of support payments to RES generation and the level of efficient short term signals (marginal production costs). Besides, system conditions like RES deployment costs could also affect the financing gap of RES generation that needs to be covered by support payments. Consequently, distortions introduced by this scheme in both long and short term signals depend on system conditions. As a consequence of all this, the performance of this option is Poor.

When **no support is provided to RES-E generation**, no distortions are created in long and short term signals, and the system outcome is not dependent of political intervention. For that reason, we understand that this scheme performs very well (Very Good) under this assessment criterion.

Political authorities could easily manipulate support to RES generation if the **application of this support is conditioned to the provision of voltage support** by this generation. This is so because authorities could easily modify the voltage support condition applied to determine which generators should receive voltage support.

RES generators which are not able to provide voltage support will not receive support for their deployment. Then, distortions in short and long term signals created by RES support will not affect these generators under any system conditions. This means that the outcome of the application of any support scheme regarding the short and long term signals perceived by this group of generators will not change with system conditions. Then, from the point of view of signals provided, mechanisms would be more robust if the voltage support condition is applied. Overall, the impact of this condition on the robustness of RES support is mixed, leading to the proposed grade being Fair.

6.3.3 Implementability

Compatibility with existing regulation/principles and markets (both long and short term)

Next, each of the design options considered are assessed against the criterion 'compatibility with existing regulation and principles', which is also related to the level of alignment between principles applied in each design option and those in place in EU countries.

FIT that result in regulated payments as well as **FIP that are regulated** produce short term energy prices earned by RES generation that do not coincide with short term marginal supply costs. These prices are somehow distorted even when the distortion is larger for FIT. Besides, assuming FIT and FIP are computed separately in each country, the principle of having markets operated in a coordinated or integrated manner is not respected either. Lastly, market competition is not applied to determine the level of support payments, thus not complying with a third principle. Hence, the performance of these schemes is Poor.

FIT and FIP computed in an auction do not result in short term prices reflecting marginal supply costs. Besides, being normally computed separately in each country, they are against the principle of market integration. However, the level of support to RES generation is computed through a competitive mechanism. Thus, the performance of these scheme is **Fair**.

Certificates are distorting short term prices earned by RES generators, as explained above. But their coordinated implementation at European level is more likely than that of other mechanisms, and support provided to RES is determined according to competitive forces. Thus, the performance of this option is **Good**.

Long term clean energy or capacity auctions are expected to be applied separately in each country, if implemented, thus not respecting the market integration principle. However, in both cases, the level of support provided to RES generation is determined through competitive means. Lastly, while capacity payments are set in the long term and, therefore, are not distorting efficient short term prices, payments resulting from energy auctions are interfering with the computation of short term prices as marginal supply costs in this time frame. Thus, the performance of long term clean energy auctions is **Fair**, while that of capacity auctions is **Good**.

Applying **Net metering of demand and generation per network user for the computation of regulated charges** results in network charges that are dependent on operation decisions by agents (their production and consumption level) and which are not related to the network costs caused by the two network users considered jointly (since both demand and generation being netted may cause additional costs). Then, network charges resulting from this scheme are highly inefficient and the performance of this scheme is **Poor**.

Applying **No support (conventional market remuneration)** to RES generation would not contradict any principle (short term efficiency, competition, and market integration). Then, the performance of this option is **Very Good**.

By **conditioning support payments to the provision of voltage support**, the remuneration of the voltage support service; RES generation capacity; and energy supply is not being set in line with the market value of these products, which is to be computed independently according to competitive mechanisms. Then, the performance of this option is **Poor**.

Level of use of funds from the public (State/local government) budget

In some systems, mechanisms related to the adoption of clean technologies have been funded from the public budget. The amount of funds provided by public authorities that are used to support RES generation should be as low possible, since these public funds are scarce. The use of large amounts of public funds by a support mechanism may condition its acceptance by authorities.

Most RES support schemes including **Long term clean energy and capacity auctions, FIT and FIP schemes,** and those where **RES support is made contingent on the provision of grid support**, do not condition the sharing of the burden of support payments between agents in the electricity sector and tax payers. In practical terms, there are cases where electricity consumers pay (most), but also exceptions to this, see (Batlle et al, 2011). Then, these schemes cannot be assessed according to this criterion.

When **Net metering of demand and generation per network user is applied for the computation of regulated charges**, increases in these charges applied to the rest of consumers compensate for the reduction in system revenues from charges paid by consumers with onsite RES generation. Then, no cost of RES support is covered by the public budget, and the performance of this option is <u>Very Good</u>.

In **Certificate schemes with Quota**, no payment is centrally made by the system to RES operators. Instead, extra payments for electricity production by RES generation are made directly by other agents in the market (suppliers, etc.). Then, this mechanism has no cost for the public budget and its performance is <u>Very Good</u>.

When **No support** is provided to RES generation, there is no burden to share, part of which could be potentially placed on the public budget. Then, the performance of this option is <u>Very Good</u>.

Cost efficiency

The overall amount of support payments provided to RES generation should be the minimum necessary to achieve the desired RES targets.

When either **Long term clean energy auctions** or **clean capacity auctions** are organized, competition may drive down support payments. However, these schemes are normally implemented separately in each country, which will increase the cost of support (not the most efficient generation over Europe is supported). If auctions are organized separately for each technology the cost of support would be lower. Besides, energy auctions resulting in FIT provide support payments that are more certain than those from capacity auctions and certainly more than those resulting from energy ones whereby FIP are determined. Then, the performance of both types of auctions is <u>Fair+</u>.

The cost of applying **Net metering of demand and generation per network user for the computation of regulated charges** is likely to be lower than that of most schemes, since only distributed RES generation (being netted with demand) could benefit from this scheme. Then, the performance of this option is <u>Good</u>.

Schemes resulting in regulated payments, like **FIT computed as Regulated Prices**, and **Regulated FIP**, do not manage to drive down payments to RES generation through competition among operators. Besides, if mechanisms are applied separately in each country, as usually done, the amount of funds to be transferred to RES generation increases. These funds can only decrease if payments are set separately for each technology. Within the two schemes, FIT provide more certainty to RES generators over future revenues than FIP, which reduces financing costs. This may be partly overcome by setting a cap and floor for final prices earned. Hence, overall, the performance of **regulated FIP** schemes is <u>Poor</u>, while that of **Regulated FIT** and **FIP ones with price cap and floor ones** is <u>Poor+</u>.

FIT and **FIP auction schemes** manage to drive down support payments by creating competition among RES operators. However, these auctions are normally organized separately for each country, which increases their overall cost. Costs may be lower for technology specific auctions. Lastly, price risks, and, therefore, financing costs, are higher for **FIP schemes without cap and**

floor, than for **FIT schemes** and **FIP schemes with a price cap and floor.** Then, the performance of the two latter is Fair+, while that of **non-constrained FIP schemes** is Fair.

Under **Certificate Schemes with Quota**, a single scheme may be applied at European level. This should result in competition occurring not only among RES operators within each country, but also at European level. This should drive support payments down significantly, especially if certificate schemes are specific to each technology. However, final prices earned by RES generation would be subject to high variability, and therefore large uncertainty, which would increase largely financing costs. All in all, the performance of this option can be deemed **Fair+**.

When **No support (conventional market remuneration)** is applied, there is no transfer of funds to RES operators. Then, the performance of this option is **Very Good**.

When **Support is conditioned to the provision of grid support services**, the amount of RES generation earning support is decreasing. Then, this measure will reduce the amount of funds transferred to RES generation, even when competition in setting the level of support payments may decrease, like the number of potential competitors for RES support. Then, the performance of the application of this condition in this regard is **Good**.

Relevance of barriers faced by RES generation for its participation in markets

Under **Long term clean capacity auctions**, uncertainty over revenues perceived by RES generators is limited, since parts of these revenues are determined (set) in the long term. However, some hedging may still be needed. This scheme does not impose direct barriers on the participation in short term markets. Overall, this design option may perform well (**Good**).

For **FIP whereby final prices are subject to an overall cap and floor, either if these FIP are regulated or are set in an auction**, the level of predictability of revenues can be deemed similar to that for Long term clean capacity auctions. There is some uncertainty about revenues but this is limited. Then, some hedging or strategy to guarantee a certain level of revenues may be required. Besides, these schemes do not impose direct barriers on the participation in short term markets. Then, overall, these design options may perform well **(Good)**.

FIP schemes without overall cap and floor prices result in overall revenues for RES generation that are subject to larger uncertainties than schemes with cap and floor prices. Therefore, hedging is needed and the need of developing an overall risk managing strategy is larger. Similarly to other FIP schemes or long term energy auctions, these schemes do not impose direct barriers on the participation in short term markets. Then, overall, these design options may perform fairly (**Fair**).

FIT schemes, both regulated or involving the organization of an auction, result in overall payments largely fixed that do not involve any interaction of agents with markets (at most, providing offers that are as low as needed). Then, participation of RES generation in short term markets under this scheme is prevented, which involves that the performance of these schemes is **Poor**.

When **Certificate Schemes with Quota** are applied, RES generation selling these certificates may be able to partly manage risks related to variations in the certificate price by deciding over the time when to sell the certificates. Thus, there may be less uncertainty over RES generation revenues than under unconstrained FIP schemes. The fact that RES operators may decide to withhold certificates until prices get higher may condition the time when they participate in short term energy markets, but this does not represent a barrier of their participation in these markets. Therefore, this design option may be deemed to have a **Good** performance.

Long term clean energy auctions provide RES generation with an extra revenue stream that may be subject to risks over the amount of energy sold and its price depending on the type of payment negotiated in the auction (CfD, FIP, etc.). In any case, some uncertainty about overall revenues exists. The higher the certainty over revenues (for CfD, for example), the higher the barriers to the participation of RES generation in short term markets, given that earning a fixed revenue for their energy production results in agents not participating effectively in markets. The lower the certainty over revenues, the higher the need for agents to build a risk hedging strategy that may turn out to be complex for them to manage. Hence, the overall performance of these design option is **Fair**.

Net metering of demand and generation per network user for computation of regulated charges results in overall revenues of RES generation being highly uncertain, since these are subject to typical market risks. Then, agents would not face special barriers for their participation in short term markets but may need to build a hedging strategy to secure a sufficient level of revenues. Then, one can conclude that this option perform fairly (**Fair**).

When **No support (conventional market remuneration)** is provided, significant uncertainty about revenues would result in some hedging strategy needed. RES generation would thus face traditional barriers in short term markets. Therefore, this design performs fairly (**Fair**) under this assessment criterion.

Lastly, when **RES Support is conditioned to the provision of voltage support**, the participation of RES generation in other short term markets would be contingent on the provision by this generation of voltage support. Hence, this mechanism would make the participation of RES generation in short term markets more difficult. The performance of this scheme is, thus, **Poor**.

6.3.4 Fairness

Long term clean energy or capacity auctions, as well as **FIT and FIP schemes resulting from an auction**, are difficult to manipulate, because the level of payments is set through a market process. An exception to this are FIP schemes, where a price cap and floor is considered, since the latter could indeed be controlled by authorities. These schemes are expected to be applied separately in each country, which could be a source of discrimination. Then, the performance of these schemes is deemed **Fair**, with the exception of FIP schemes with an overall cap and floor, which may perform between poorly and fairly (between **Poor** and **Fair**).

FIT and FIP fully regulated schemes are easy to be manipulated by authorities and their separate application in each country would create unfair discrimination. Hence, their performance is **Poor**.

Certificate Schemes with Quota are based on market solutions, and therefore difficult to manipulate. Besides, they could easily be implemented at European level not creating distortions of cross-borer competition. The same can be said about **Not providing support to RES**, since the energy prices they earn should be computed in fully coordinated markets. Then, their performance is Good to Very Good.

Both **Net metering schemes of demand and generation per network user for the computation of regulated charges** and **making support contingent on the provision by RES generation of voltage support** are schemes that can be easily manipulated (regulated charges are subject to the control of authorities and the condition related to the provision of voltage support can be easy modified by authorities as well). Besides, both regulated charges and the voltage support condition would normally be applied separately in each country, creating distortions of fair competition. Then, the performance of both options is Poor.

6.4 Conclusions

In the previous section, options for RES support have been assessed according to their impact on the short term functioning of the system.

Table 18 **Error! Reference source not found.**presents a summary of the assessment of RES support schemes according to the aforementioned criteria, which have been classified into Efficiency, Robustness, Implementability, and Fairness ones. Very weak and weak grades are highlighted in red and light orange, while very good and good grades are highlighted in green and light green.

It can be concluded that:

- Net metering of demand and generation, all types of FITs, regulated FIP and the support conditioned to the provision of grid support services have some serious drawbacks, or do not perform well on average terms, and should be discarded as sound options to implement.
- Long term clean capacity auctions and "No support" options perform very well in terms of their impact on the short-term functioning of the market, whereas Long term clean energy auctions, FIP resulting from an auction and Certificate schemes perform well.

Complementing Table 18: *Summary of the assessment of RES support schemes according to the four families of criteria*, Figure 10**Error! Reference source not found.** provides the main arguments considered to classify RES support options explored into promising ones (Long term, clean energy or capacity acutions, Certificate schemes, and FIP resulting from an auction) and those others to be discarded. Arguments are provided in the form of strong and weak points of each of the two groups of design options defined. Although with overall strong grades in the assessment criteria hereby considered, we would discard the "No support" option since it performs very poorly in terms of long-term effectiveness (see Market4RES report D3.1) and, therefore, cannot comply with the policy objectives set for RES targets in the long-term.

6.5 Overall assessment and selection of best options considering both their short term and long term effects

Lasstly, taking into account the assessment and ranking made of RES support schemes according to both their short and long term effects, RES support schemes are assessed in overall terms, see Figure 11. Support schemes are classified into most promising options (Green) and those to be discarded (Bad). Main reasons supporting the classification that has been made of schemes are provided as well. Most promising options overall to investigate turn out to be Long term clean capacity auctions, Long term clean energy ones, Certificate schemes, and FIP auctions.

Table 18: *Summary of the assessment of RES support schemes according to the four families of criteria*

		Long term clean capacity auctions	Long term clean energy auctions	Net metering of demand and generation	FIT with Regulated Prices	FIT with auction	FIP regulated with no price cap and floor	FIP regulated with overall price cap and floor	FIP resulting from an auction with no price cap and floor	FIP resulting from an auction with overall price cap and floor	Certificate Schemes with Quota	No support	Support conditioned to the provision of grid support services
Efficiency	*Marginal cost reflectivity*	Very Good	Fair for FIPs Poor for FITs	Fair	Poor	Poor	Fair	Fair-	Fair	Fair-	Fair	Very Good	Fair+ for FIPs Poor+ for FITs
	Cost causality	Very Good	Good	Poor	Poor	Poor	Good	Fair	Good	Fair	Good	Very Good	Good for FIPs Poor+ for FITs
	Liquidity	N.A.	N.A.	Fair or Good	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	Very Good	N.A.	N.A.
	Global coherence	Good to Very Good	Fair for FIPs Poor for FITs	Poor	Poor	Poor	Poor	Poor	Fair-	Fair-	Good	Very Good	Poor to Fair
Robustness		Very Good	Fair	Poor	Poor	Fair	Poor	Poor	Fair	Fair	Fair	Very Good	Fair
Implemen-tability	*Compatibility with regulation*	Good	Fair	Poor	Poor	Fair	Poor	Poor	Fair	Fair	Good	Very Good	Poor
	Relevance of barriers	Good	Fair	Fair	Poor	Poor	Fair	Good	Fair	Good	Good	Fair	Poor
	Level of use of public funds	N.A.	N.A.	Very Good	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	Very Good	Very Good	N.A.
	Cost efficiency	Fair+	Fair+	Good	Poor+	Fair+	Poor	Poor+	Fair	Fair+	Fair+	Very Good	Good
Fairness		Fair	Fair	Poor	Poor	Fair	Poor	Poor	Fair	Poor to Fair	Good to Very Good	Good to Very Good	Poor

Design Options	Weak points (-)	Strong points (+)
✓ Long term clean capacity auction ✓ Long-term clean energy auction ✓ Certificates ✓ FIP (auction)	• FIP (auction), Certificates, and energy auction create non-negligible distortion of short term prices • Distortions created by FIP (auction), Certificates, and energy auction are not stable • Relevant amount of support provided • Create some barriers to RES participation in markets	• Limited distortion of efficient short term signals (negligible for LT clean capacity auction) • Tend to foster liquidity as revenues (partially) depend on spot market prices • Certificates promote Cost Causality • Resilient to political intervention
✓ FIP regulated ✓ Net metering ✓ FIT ✓ Support conditioned to the provision of grid support	• All create relevant distortion of short term prices (FIT-largest, FIP regulated-relevant, Net Metering-localized) • FITs, Net Metering, and Voltage condition reduce liquidity in short term markets • Prone to political intervention • Large support for regulated FIT and FIP • Create some barriers to RES participation in markets	• FIP regulated promotes liquidity in short term markets • Low overall support involved in Net Metering • Grid support condition reduces the amount of support mobilized

Most promising design options (overall strong grades) — Discarded design options (overall weak grades)

Figure 10: *Classification of RES support options into weak and strong ones from the point of view of their impact on the short term functioning of the system and arguments considered for this*

Design Options	Weak points (-)	Strong points (+)
✓ Long-term clean capacity auction ✓ Long-term clean energy auction ✓ Certificates ✓ FIP (auction)	• FIP (auction) and Certificates imply some project risk • FIP, Certificates, and energy auction distort short term prices to some extent, and this distortion depends on system conditions • LT clean auction difficult to extend to other markets (involves central buyer) • Relevant amount of support provided • Create some barriers to RES participation in markets	• Tend to reveal the marginal cost of RES capacity in LT procurement schemes for new projects • Effective to meet LT RES targets • Limited distortion of efficient short term signals • Tend to foster both LT and ST liquidity • Certificates promote Cost Causality • Resilient to political intervention
✓ FIP regulated ✓ Net metering ✓ FIT ✓ Support conditioned to the provision of grid support	• May not reflect marginal cost of RES capacity for new projects • Fail to meet LT RES targets • All create relevant distortions of short term prices (FIT-largest, FIP regulated-relevant, Net Metering-localized) • FITs, Net Metering and , and Voltage condition reduce liquidity in short term markets • Prone to political intervention • Regulated FIP and FIT: Large support	• FIP regulated promotes liquidity in short term markets • Low overall support involved in Net Metering • Grid support condition reduces the amount of support mobilized • Experience within the EU • Can be extended to other systems

Most promising design options (overall strong grades) — Discarded design options (overall weak grades)

Figure 11: Overall classification of design options into Strong and Weak ones, considering their short and long term effects, and reasons supporting this

7 Participation of demand in short term markets

Within this section, the participation of demand in short term markets is analyzed and most promising schemes to organize this are identified. Short term markets where demand is to participate are of two main types: reserve markets, which are a capacity market, and short term energy markets. First, general principles, or conditions, for the participation of demand in short term markets are discussed. Then, the criteria used to assess the performance of schemes for the participation of demand in markets are identified and described. These criteria happen to be common to both the participation of demand in reserve markets and its participation in energy markets. Afterwards, the participation of demand in each of these two types of markets is analyzed separately. First, possible schemes for the participation of demand in reserve markets are identified and assessed, getting to some conclusions. Then, options for the participation of demand in energy markets are also presented and assessed.

7.1 General principles

7.1.1 Demand response and the short-term markets

The long-term valuation of demand-side response (DSR) through its participation in capacity markets is one of the topics exposed in the Market4RES deliverable D3.1 *"Developments affecting the design of long-term markets";* the present document will expose their participation in operational reserves (i.e. in short-term capacity or flexibility) markets in similar terms since the market designs allowing DSR to participate in reserve markets are the same as those for capacity mechanisms. It will then detail and assess the options for DSR to participate in short-term energy markets (including balancing).

7.1.2 Conditions for a market fit of DSR

Several technical and institutional aspects constrain the development of demand response:

- most (residential) consumers remain equipped with meters that are not sophisticated enough to precisely measure their efforts in terms of load shedding which limits the opportunity to value demand response through the retail market;
- wholesale and balancing markets require minimum quantities that are incompatible with the shedding capability of most consumers; their actions must therefore be coordinated by an aggregating entity;
- in the absence of intended market arrangements, the supplier being in most case the intermediary between the wholesale market (its price reflecting the value of electricity at a given time) and the consumers, it has exclusive access to its consumers' flexibility; there is therefore no competition in the aggregating market which restrains the development of DSR and limits it to an implicit tool to balance the suppliers own portfolios.

There are therefore three steps in building a DSR-capable market design:

(i) A DSR-compatible market design enable explicit participation of demand in all markets, which means setting up the necessary financial arrangements and measurement and verification methods to enable aggregators to sell energy blocks backed with load shedding exactly as if they were backed with production (and, in fact, they *are* since the energy initially produced to cover the consumption of the shed consumers is sold to another one);

(ii) A DSR-friendly market design involves an adapted governance framework to make it possible for aggregators to fully compete with suppliers by not requiring the approval of the latter for their actions on their consumers' load and benefitting from high level of confidentiality on the result of these actions; moreover, specific market products (especially in minimum bid size) are set up;

(iii) Finally energy policy-makers may want to foster DSR through specific support schemes; their range is roughly the same as for support to RES and they will not be studied in details in this section; however it should be noted that subsidies proportional to capacity (long and short term DSR capacity auctions for instance) could be very relevant, as in the case of RES for long term capacity auctions, therefore not distorting other markets: because of its characteristics of flexible (short term) and peaking technology, a large share of DSR's value lies in capacity.

7.2 Assessment criteria used to assess the several DSR schemes (options)

The assessment criteria will be the same for reserve markets and energy markets. They can be classified into efficiency, implementability, and fairness ones.

Efficiency

1. **Marginal cost reflectivity**: Efficient DSR activations are based on an arbitrage between the market value of energy and its usage value at a specific point in time. The market design must ensure that DSR is activated when instant market value goes above the consumer's usage value.
2. **Cost causality**: DSR dedicated companies with direct market activity are new entities in the market design. Their activity interferes with existing market entities, such as Balance Responsible Parties (BRPs). Overall efficiency requires that the incentives for all parties are preserved, by ensuring which must ensure that they bear the costs associated with their activity.
3. **Liquidity**: Does the DSR market design foster market activity rather than internal portfolio optimization?

Implementability

1. **Feasibility**: DSR resources are technically complex and difficult to manage, and their management requires a dedicated expertise. In this regard, market design assessment must take into account the fact that whether dedicated DSR companies specializing in aggregation are allowed to operate or not.
2. **Compatibility & simplicity**: These 2 criteria can be assessed together, to consider the additional market design complexity associated with DSR participation.
3. **Implementation costs**: The massive roll out of smart meters represents a significant implementation cost to enable DSR. More "targeted" market designs can feature lower implementation costs.

4. **Level of use of public funds**: DSR is a politically attractive technology / activity, which can attract public support. This criterion must be put in perspective with the Efficiency criteria.
5. **Scalability**: Is the market design for DSR compatible with existing cross-border solutions or not?

Fairness

1. **Competition**: Is unbundling between DSR and Supply possible? Can independent DSR companies have access to consumers without the authorization of their supplier?
2. **Confidentiality** (applies only where competition exists): Are DSR activations individually notified to suppliers? Is consumer data managed by the DSR service provider kept confidential or is it accessible to potential competitors?
3. **Allocation of implementation costs.**
4. **Level playing field for DSR**: Are the incentives for DSR equivalent as the ones for generation?

7.3 Regulation of demand participation in reserve markets

7.3.1 Description of options

Reserve markets aim at providing an insurance against short term risk on security of supply due to a contingent and temporary discrepancy between production and consumption, leading to load shedding. Traditionally, generation units provide the system with available flexible capacity, ready to be called upon by the SO (operational reserve); we explore options to enable the participation of demand in reserve markets.

Explicit participation options

The most common way for demand to participate in reserve markets is explicitly through a process allowing demand response to compete with traditional generation and fits in a more or less standard reserve or reserve product. This theoretically involves:

- a qualification process, by which the operator of a DSR facility shows its ability to timely alter the load of the consumers constituting this facility so as to actually replace an increase in production by a decrease in consumption with similar flexibility characteristics;
- a certification process, by which the operator commits to be available;
- a verification process, possibly associated with a penalty scheme in case the availability commitment is not observed. In practice, it can be quite difficult to measure the level of availability of demand response.

Implicit participation options

Depending on the design of the reserve markets, demand can also be able to participate implicitly in these markets. This is the case if the suppliers have, under the reserve mechanism's provisions, an obligation based on their actual (measured) consumption.

Although this participation mode is clearer for long-term capacity markets, it can also exist in operational reserve markets which arrangements may also be so that suppliers are responsible for provisioning reserves or, at least bear a part of the cost depending on their consumption (possibly during periods of shortage of reserve in arrangements of the "scarcity pricing of operating reserve" type). Similarly to what happens in capacity markets, they may want to be able to adjust their consumption through DSR during these periods to control their participation in operational reserves.

Mutual compatibilities and exclusions

The participation of demand in reserve markets can be envisaged in the following ways:

- explicitly through certification: in this case available and flexible load shedding capacity plays the exact same role as available (flexible) generation;
- implicitly if the consumers have an obligation in the mechanism based on the consumption of their customers during specific periods of time (respectively peak hours and periods of reserve scarcity).

Depending on the market arrangements, it may be possible (and sometimes encouraged) to participate in a capacity market and in reserve markets. For instance, a DSR-able site offering operational reserve (explicit participation) may have been certified for providing long-term capacity if the capacity mechanism's certification process is based on physical availability of the capacity during a peak period (regardless of its participation in any short term market). However, if it is used by a supplier to reduce its obligation under the capacity mechanism, it can of course no longer be used to provide reserve during these hours nor by the supplier to adjust its imbalances to avoid being short in a reserve scarcity period (provided this period is included in the capacity mechanism's peak hours) since it has already been shed.

Thus, explicit participation in capacity and flexibility markets may be fully compatible, whereas implicit participation in one or the other of these markets may partly prevent to use DSR for other purposes (since implicit use requires actual activation). Therefore, the options cannot be assessed one against the others and they should be seen as different bricks of market design, each one revealing a part of the value of demand response (all the more as demand response objects are extremely diverse).

7.3.2 Assessment of design options for DSR participation in reserve markets

Explicit participation in reserve markets (DSR dissociated from supply)

Efficiency

Assuming a perfect control process (i.e. that it is possible to perfectly measure DSR availability), explicit participation in reserve markets allows commandable demand response objects to compete on equal footing with generation capacity thus allowing to significantly reduce the cost of ensuring the system's reliability by **reflecting the marginal cost** of using a new way to deal with it (namely DSR).

Setting it up **improves *cost causality*** as compared to not allowing DSR explicit participation since consumers can decide that they are willing to help the system by being available to reduce their consumption in periods of reserve scarcity, if the price for this service is high enough. The consumers who do not want to provide this service at any price thus bear the cost of their inelasticity. It also increases the number of options to ensure reliability and the price-elasticity of supply, therefore it has a **positive impact on liquidity** in reserve markets.

Implementability

Having demand response explicitly participating in a reserve market implies being able to certify it, which is extremely uneasy since, potentially, every single load can be considered as able to respond from the moment it has a circuit breaker. The control process is therefore key and may be very complex to design and introduce bias; for these reasons, this option suffers from a **poor feasibility**.

For the same reason (very complex monitoring process), it **cannot be regarded as simple**; it however makes reliability mechanisms a powerful tool to promote demand response, hence a **good compatibility** with the European energy policy objectives.

Setting up explicit participation of DSR may be expensive because of the need for a very complex control process, but it should still be very far from the benefit, hence such an option should be regarded as **good from a cost perspective**.

DSR participation in a reserve markets **should not involve the use of public** funds except if DSR is subsidized and the operator's participation in such a market is covered by a management premium.

Finally, the technological scalability of this option is only **fair** for flexibility mechanisms because it requires a relatively good direct control on load which may exclude small loads. Cross-border participation (geographical scalability) depends on future arrangements on the possibility to reserve interconnection capacity for operating reserves.

Fairness

The **impact of this option on competition is good.** Competition in reserve markets is improved by explicit participation of demand response. According to the precise arrangements, it is feasible for a third party (independent from the supplier) to access to the consumers, which creates competition at this level. However, a high level of confidentiality must be ensured so as to ensure a level playing field between aggregators and suppliers.

Implement costs **may not be perfectly fairly allocated**, in particular those linked to monitoring and verification processes, could be partly borne by the system operator.

This option **creates a level playing field** for DSR to participate on equal footing with generation in flexibility markets.

Implicit participation in reserve markets

Efficiency

If the consumers (through their suppliers) are responsible of provisioning reserves, they can arbitrate between contracting with flexible capacity holders (or pay for the SO to contract reserve) or try to limit their obligation by reducing their consumption during the "reserve scarcity periods"; to that extent, implicit participation of DSR in (eligible) reserve mechanisms can be seen as the part of the demand curve that is not at any price; this option **improves marginal price (in fact marginal utility) reflectivity** of a flexibility mechanism. This said, fully activating demand response may not be the best option for all kinds of DSR and having it simply available (and sold explicitly as reserve) could be enough to ensure SoS, therefore implicit participation may be too costly to represent the value of all types of demand response in a perfect manner.

The consumer theoretically arbitrates between consumption and DSR activation according to his utility to consume during the periods of tension on reserve given its price: **cost causality is excellent**, leading to maximizing social welfare. However, in practice the final consumers may participate in the mechanism through their supplier and the price signal may be altered when it reaches the consumers.

Allowing implicit participation of demand in flexibility mechanisms increases the number of options to ensure reliability and the price-elasticity of demand, but, DSR being managed in-portfolio, it has **no impact on liquidity**.

Implementability

This option is by easier to set up than explicit participation since a decrease in consumption is easier to measure than the availability of a DSR facility. As a consequence this option is **easily feasible**.

Implementation costs should be relatively low although this option requires being able to precisely measure consumption (allocation to a specific supplier could be an issue where load is profiled).

This option **does not require the use of any public funds.** Scalability is not relevant to this option.

Fairness

This option decreases market power in the mechanism by elasticizing demand but it does not let third parties to reach consumers and operate demand response in flexibility markets freely from the supplier's consent. Its **impact on competition is therefore limited.**

Implementation costs are fairly allocated since they are fully borne by the supplier.

This option **allows extending the role of demand response** beyond what generation is able of but, if implemented without explicit participation, does not create a level playing field with generation.

7.3.3 Conclusion on regulation of demand participation in flexibility markets

Table 19 synthesizes the previous analysis. Overall, none of the options should be preferred but both of them should be implemented where relevant (i.e. in systems where an eligible mechanism exists) to make room for all types of demand response objects and of market arrangements (operated by the supplier in portfolio or marketed; operated and marketed by a third party). Table 20 provides a detailed summary of the assessment of otions according to each main block of criteria (Efficiency, IMplementability, and Fairness) together with main arguments considered in the assessment.

Table 19: Summary of the assessment of options for the participation of demand in reserve markets

		Implicit participation	Explicit participation
Efficiency	Marginal cost reflectivity	Good	Very good
	Cost causality	Very good	Very good
	Liquidity	Poor	Very good
Implementability	Feasibility	Good	Poor
	Compatibility & simplicity	Very good	Fair
	Implementation costs	Very good	Good
	Level of use of public funds	Very good	Very good
	Scalability	N/A	Fair
Fairness	Competition	Fair	Good
	Confidentiality	Poor	Good
	Allocation of implementation costs	Good	Fair
	Level playing field for DSR	Very good	Very good

Table 20: Detailed summary of the assessment of options for the participation of demand in reserve markets

	Efficiency	
Implicit participation	Good / very good	Allows DR to compete in the mechanism, therefore improves its overall efficiency. Well suited to lower variable cost options since they have to be activated.
Explicit participation	Good / very good	Allows DR to compete in the mechanism, therefore improves its overall efficiency. Well suited for higher variable cost options since only availability is required.

	Implementability	
Implicit participation	Good	Reasonably complex, relatively scalable since a large part of demand can participate. No use of public funds.
Explicit participation	Fair	Costly and very complex, especially regarding the monitoring/control process. Scalability may be limited due to the need for some degree of precision.

	Fairness	
Implicit participation	Fair	Decreases market power in the mechanism by elasticizing demand. But only suppliers can participate: little competition and no confidentiality issue.
Explicit participation	Good	Increases competition in the supply side. Confidentiality is an issue for DSR to be operated by aggregators.

7.4 Regulation of demand participation in short term energy markets

7.4.1 Description of options

Different approaches can be considered to make DSR able to be valued in the short term and very short term energy markets (balancing). Like in the case of capacity and reserve markets, DSR can be valued implicitly or explicitly:

- "Implicitly" in the electricity retail market, through the supplier, if DSR provisions are integrated in the supply contract. In this case, the DSR operator is the supplier (2 options)
- "Explicitly" in the wholesale market (day-ahead, intraday and balancing energy markets), through an independent DSR aggregator or directly by the consumer. There are two main options for this kind of valorisation:
    - there is a bilateral agreement with the supplier about DSR (1 option)
    - there is no bilateral agreement with the supplier about DSR (2 options)

The five market design options are described below and represented in Figure 12; all five are relevant to energy markets (day-ahead and intraday mainly) and balancing except the first one which consists, for the supplier, in sending a price signal to a multitude of loads. Such control may not be precise enough for balancing, first because in most cases, the price signal is too simplistic (multi-index meters) and second because even in the case of a dynamic pricing sent in real time, it would require the supplier a degree of precision on the knowledge of the price versus quantity curve that is uneasy to achieve.

The proposed market designs are centered on the consumer, which has a supply contract with a supplier. This supplier is itself part of the portfolio of a BRP, which is sourcing energy on the market to cover the demand of the consumer.

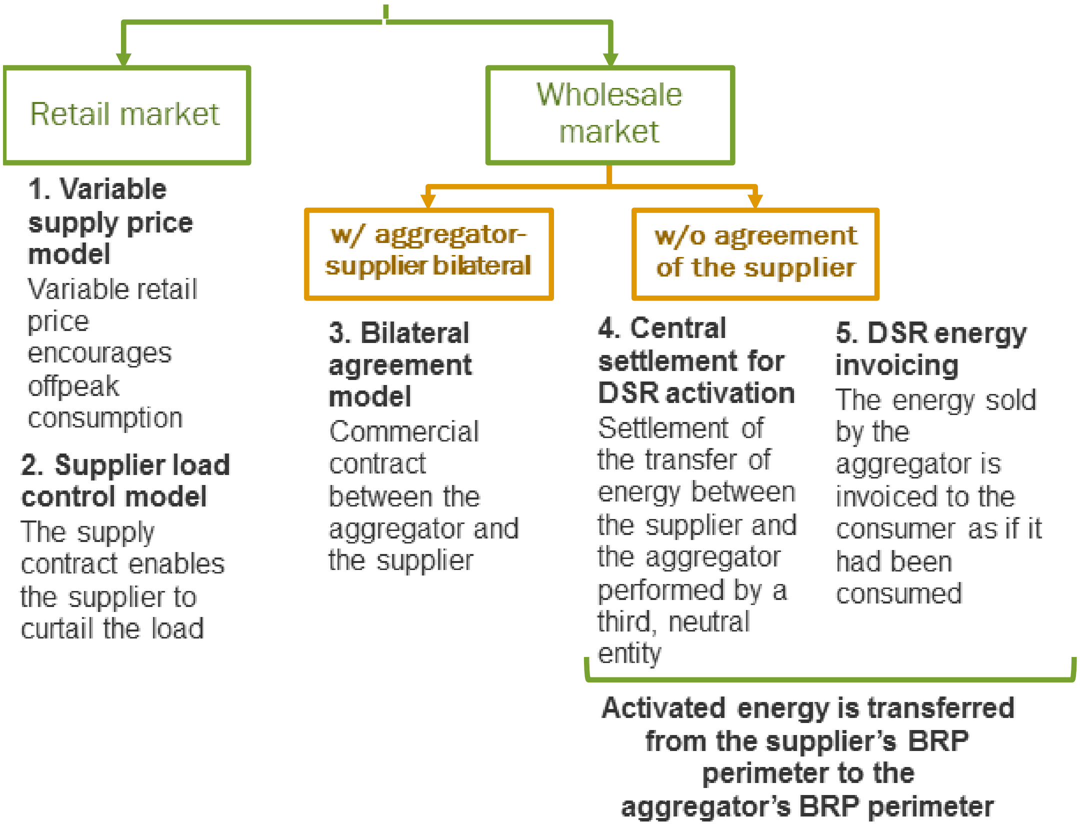


Figure 12: classification of design options considered for the participation of demand in energy markets

In some market designs, the consumer itself or an independent aggregator on its behalf (with which the consumer has a DSR contract) can have a market activity. This market activity formally requires association with a BRP to access the energy market and being a Balance Service Provider (BSP) to access the Balancing market.

Market designs with DSR integrated in the supply contract (implicit participation)

These market designs are based on the principle that suppliers are at the interface between consumers and markets (retail and wholesale markets), and therefore well placed to value DSR. Flexibility clauses can be integrated in a supply contract, giving the supplier additional tools to optimize its portfolio and reduce the sourcing costs. In return, the consumer may reduce its electricity bill (but not necessarily its electricity consumption if consumption is just postponed) compared with a standard supply contract.

No other market participant is impacted, and all the details are settled in a bilateral contract between the supplier and the consumer. Two market design solutions can be implemented, depending on whether the consumer receives price incentives or direct load variation orders from the supplier.

Option 1: Variable Supply Price model

In this model, the consumer pays a variable supply price to the supplier. The possible variations of the supply price are set contractually, and the consumer can adapt its consumption in response to price variations (the decision rests with him, depending on the utility the consumer has from energy use). Supply price indexation on market prices makes the price signal more accurate, but also more risky and complex to manage for consumers. The supplier anticipates the behaviour of the consumer in response to the price signal and this information is used by the BRP to balance its portfolio. This model represents a large share of existing DSR in Europe, notably for small consumers equipped with smart meters.

Option 2: Supplier Load Control model

The flexibility clause in a supply contract can provide for direct supplier load control in specific situations. In such cases, the consumer is expected to curtail its load of a predefined volume, which can for instance be used by the BRP to take part in balancing markets, to self-balance its portfolio or to benefit from high market price situations. This type of integrated supply & flexibility offers typically target industrial consumers.

Market designs with DSR dissociated from supply (explicit participation)

Market designs dissociating DSR from supply gives direct market access to the consumer or to an independent aggregator on its behalf to sell DSR on the market. In such market designs, the consumer may have two different contracts: a supply contract with the supplier and possibly a DSR contract with an independent aggregator. Access to the day-ahead and intraday energy markets would then take place through the aggregator's BRP, not through the supplier's BRP.

Market Design with Bilateral Agreement

Option 3: Bilateral Agreement model

The Bilateral Agreement model is a market design in which the aggregator and the supplier's BRP conclude a bilateral agreement to solve the specific market design issues arising from the dissociation of DSR from supply. By nature, this model requires the supplier or the supplier's BRP to be involved in the agreement, which implies that the "confidentiality" issue is not solved with this market design.

This bilateral agreement is a commercial contract between the aggregator and the supplier's BRP or the supplier itself. However, it requires that both parties are willing to enter in such a bilateral framework contract, hence competition issues can arise.

In case the aggregator is the consumer itself, the bilateral agreement can be included in the supply contract. In such a case, the only difference with an integrated supply and flexibility situation considered above is that the consumer has a market activity of its own and initiates DSR activations.

To solve the "transfer of energy" and the "supplier's BRP imbalance risk", the bilateral agreement covers the settlement of the transfer of energy between the supplier's BRP and the aggregator in case of DSR activation. Typically, a bilaterally agreed transfer price is paid to the supplier's BRP by the aggregator for the energy sold on the market. Such provisions can take the form of a delegation of balancing responsibility.

Market Designs without Bilateral Agreement

Market designs without Bilateral Agreement allow aggregators to act independently of suppliers. These models differ from the Bilateral Agreement model in the way the transfer of energy is dealt with and settled between parties.

In a market design without Bilateral Agreement, the supplier's BRP imbalance risk is solved by neutralizing the activated energy (i.e. delta between baseline and metered energy) in the supplier's BRP perimeter. During the imbalance allocation process, the calculated activated energy per supplier's BRP and per imbalance settlement period is used to perform supplier's BRP imbalance risk neutralization and the settlement based on the conditions of the existing BRP contract. Hence, the calculated activated energy is assigned to the BRP source perimeter.

Potential deviations between the requested energy and the activated energy are allocated to the aggregator (e.g. as an imbalance for a BRP associated with the aggregator) and settled accordingly.

The information issue for supplier's BRP is tackled by imposing aggregators to schedule DSR activations and inform the TSO, in a similar way scheduling obligations apply for generation, including location information if relevant. The TSO notifies/informs the supplier's BRP in due time with the requested flexibility activation at an aggregated level in order to avoid counter balancing while protecting confidentiality.

This model requires an independent third party, such as the TSO, to manage the aggregation of perimeters, to determine and implement measurement and verification methods, to ensure transparency and confidentiality.

Option 4: Central Settlement for DSR activations

In this model, the settlement of the Transfer of Energy is performed by a neutral central entity, which can be the TSO or another third party. The Central Settlement model requires a bidirectional wholesale settlement price between the aggregator and the supplier's BRP to settle the transfer of energy. This settlement price is:

- Either the individual supply price of the activated consumers, which raises feasibility issues because it implies that all individual supply prices are centralized at this neutral entity.
- Or a reference price which requires some form of regulatory approval. Such a price can be a segment price per type of customers, or a price formula reflecting the market based settlement price.

Option 5: DSR energy invoicing

In this model, the energy sold on the market by the aggregator is invoiced to the consumer by the supplier as if it had been consumed. This way, the transfer of energy is settled directly between the consumer and its supplier at the supply price.

In case the aggregator is not the consumer itself, compensation from the DSR operator to the consumer is necessary, at least to cover the costs of the non-consumed invoiced energy. Such arrangements come under the contractual relationship between the aggregator and the consumer.

The supplier can receive merged metering information for each consumer, or separated metering information for the consumed energy and the energy of DSR activations without distinction between the consumed energy and the energy of DSR activations. This merging process is performed by the metering entity, for instance a DSO or the TSO.

7.4.2 Assessment of options

Variable supply price model

Efficiency

Theoretically, this model could be perfectly efficient if the supplier proposes a retail price with a variable component strictly equal to the wholesale price, but in practice this **efficiency may be limited** by the existence of a gap between the retail and wholesale prices or if the variations of the retail price are too complex to manage for the consumer. The **cost causality is good** in this model where the consumer arbitrates between consumption and DSR activation according to his utility to consume and to the retail price of energy, but this arbitrage may be partly inefficient since the latter does not always reflect the wholesale price (retail price is rarely dynamic enough). If the retail price reflects exactly the wholesale price and if the consumer is able to adapt efficiently the consumption, this model leads to maximal social welfare. This model has **no positive impact on liquidity** in the wholesale market.

Implementability

This model has the advantage of being **fairly feasible**: any supplier can propose to its customers a DSR specific supply price. It requires analysis to estimate the reaction of customers, in terms of electricity consumption, to a given price signal. Dynamic supply price however requires the suppliers to equip with multi-index meters and, for real-time pricing, they need to establish a way to communicate to their customers the evolution of the supply price.

From a market design perspective, a bundled approach for supply and DSR is the **simplest** way to implement DSR, and avoids interfering with other stakeholders. Consumers can deal with one single actor for supply and flexibility: the supplier.

Implementation costs are limited. Specific meters can be useful for consumers, as supply price varies over time. **No public fund is needed** in this model, apart from those borne by the party managing the price signal, if this party is financed by public funds.

Finally, this model is **highly scalable**: DSR can be valued through supply price for any kind of consumer (industrial, commercial, residential). As DSR is managed in portfolio, geographic scope is not an issue and the compatibility with existing cross-border solutions is not relevant.

Fairness

One major concern with this model is that once they choose their supplier, consumers cannot contract with another player one to value their flexibility, the latter being directly valued through the supply contract. In other words, there is virtually **no competition** in the access to this flexibility (the supplier has a monopoly).

This model involves **no confidentiality issue** as only the supplier and the consumer are involved in the supply contract. **Implementation costs** are borne by the supplier, and possibly by the consumer if included in the supply price. This **allocation is fair** as suppliers and consumers are the actors benefiting from DSR activations. In some case, the TSO can be involved in the price signal management and support the corresponding cost (e.g. in France since 2014).

Supplier load control model

Efficiency

The supplier arbitrates between consumption and DSR activation according to the wholesale price (paid by the supplier in case of consumption) and the retail price (earned by the supplier in case of consumption) of electricity, which is optimal from an economic point of view. Thus being **good**, the **efficiency** of this model is however limited by the fact that the consumer's utility to consume is not necessarily well (if at all) taken into account in the supplier load curtailment decision, which this may not lead to maximal social welfare. This model should have a **positive impact on liquidity** in the wholesale market since it allows suppliers to add new bids corresponding to DSR products.

Implementability

This kind of arrangement seems **fairly feasible** since any supplier can propose to its customers a load control service but, on the other hand, it requires the installation of specific devices in order for the supplier to be able to remotely control the load.

From a market design perspective, a bundled approach for supply and DSR is the **simplest** way to implement DSR, and avoids interfering with other stakeholders. Consumers can deal with one single actor for supply and flexibility: the supplier.

Implementation costs can be relatively significant (depending on the size of the aggregated consumers); they are linked with the installation and management if specific devices to control the load. **No fund is needed** in this model.

The **scalability** of this model is **limited**: remote load controls, due to its associated costs, is particularly adapted to large industrial consumers, and far less to households. As DSR is managed in portfolio, geographic scope is not an issue and the compatibility with existing cross-border solutions is not relevant.

Fairness

One major concern with this model is that once they choose their supplier, consumers cannot contract with another player one to value their flexibility, the latter being directly valued through the supply contract. In other words, there is virtually **no competition** in the access to this flexibility (the supplier has a monopoly). The consumer cannot value its flexibility outside the load control actions of the supplier.

This model involves **no confidentiality issue** as only the supplier and the consumer are involved in the supply contract. **Implementation costs** are borne by the supplier, and possibly by the consumer if included in the supply price. This **allocation is fair** as suppliers and consumers are the actors benefiting from DSR activations.

Bilateral agreement model

Efficiency

The economic **efficiency** of this option can be regarded as **fair** on average; it depends on the conditions set in the contracts between the aggregator and the supplier. Typically, if the conditions for the supplier's BRP to agree aggregator's activity are restrictive, the valuation of consumer's flexibility may be weak. The conditions set in the contract do not necessarily reflect the optimal arbitration between the DSR social value and the loss of utility for consumer, hence a potentially limited **cost causality.** This model should however have a **positive impact on liquidity** in the wholesale market since it allows aggregators to add new bids corresponding to DSR products.

Implementability

The bilateral agreement model is relatively **easy to implement.** The bilateral agreement model is the most simple market design allowing independent aggregators to operate. However, this apparent simplicity in terms of market design hides a **complexity borne by the actors** engaged in the agreement.

The **implementation costs** (transaction costs mainly) should be relatively **reasonable**: they are borne by the supplier and the aggregator, since they have to find contractual arrangements. The more difficult it is for them to find an agreement, the higher would be the transaction costs.

No public fund is needed in this model.

Finally, this model is **highly scalable**: the bilateral agreement model can apply to all kinds of consumers (industrial, commercial, residential), since an agreement is found between the aggregator and the consumer's supplier. It is compatible with existing cross-border solutions (the aggregator has however to be part of the portfolio of a BRP in the control area(s) where the load shedding takes places).

Fairness

Competition issues remain for aggregators which cannot operate with confidentiality and depend on the goodwill of suppliers (BRPs) to enter in bilateral agreements. If the BRP refuses to sign bilateral agreements with aggregators, or only at an excessive transfer price, it can exert a form of monopoly over flexibility. The introduction of standard contract templates defined by regulation can facilitate the conclusion of such bilateral contracts and provide for easier regulatory monitoring and competition oversight. On another hand, participation of consumers enhances competition in the markets (balancing market, wholesale market…).

Confidentiality issues are a very problematic. A market design allowing the dissociation of supply and flexibility is indeed not exclusive of bundled solutions. Aggregators and suppliers are therefore competitors to get access to DSR potential. It is a core business for aggregators to identify and develop a DSR potential. If DSR activations are notified at individual level to suppliers of affected consumers, these suppliers benefit for free from the identification efforts of the aggregators and are able to track every move of their DSR dedicated competitors.

Implementation costs are well distributed between on the one hand the supplier, and on the other hand the aggregator and the consumer. As they express their consent in the agreement, it ensures fairness for impacted stakeholders.

Central settlement for DSR activations

Efficiency

A market party can only sell energy if it owns it, either from generation or from purchase. DSR in itself is not equivalent to "energy", because declining to buy a good is not the same thing as creating or purchasing it. DSR therefore cannot be sold on energy markets if not backed by a positive imbalance, which is maintained by the supplier's BRP. Rather than selling energy, an aggregator is transferring or rerouting energy from the supplier's BRP to another market party. Any transfer of energy must therefore be associated with a fair compensation from the aggregator to the supplier's BRP or the supplier itself and preserve balancing incentives. If this condition is fulfilled, the **costs are properly allocated** to the responsible actors, and financial impacts on BRPs are neutralized. Therefore, this model is also **fairly efficient.** It could be perfectly efficient if the price to settle the transfer of energy with suppliers is cost reflective but this transfer price is likely to differ from the real supply price of impacted end-users.

Finally, it has a **positive impact on liquidity** in the wholesale market since it allows aggregators to add new bids corresponding to DSR products.

Implementability

Such solution requires heavy and **complex** evolutions of the market design, and lead to deep evolutions in terms of operational aspects (information systems, control methods, operational process). The transparency and confidentiality issues can lead to contradictory requirements, with diverging interests between BRPs and aggregators. A balance must therefore be found between those principles, to facilitate competition between aggregators and suppliers while preserving the fundamental role of BRPs in the market design. Trying to ensure both principles at the same time can rapidly increase the complexity of the associated market design.

Ensuring transparency and confidentiality requires an important implication of the independent third party, with **implementation costs higher than in the other models.**

This model makes **little use of public funds**, as some costs could be borne by the independent third party, such as aggregation perimeters management, management and verification tasks…

Finally, this model is **highly scalable**: the central settlement model can apply to all kinds of consumers (industrial, commercial, residential). It is compatible with existing cross-border solutions (the aggregator has however to be part of the portfolio of a BRP in the control area(s) where the load shedding takes places).

Fairness

Market designs without bilateral agreement **enable full competition** in the access to flexibility by (i) allowing aggregators to act without depending on supplying BRPs and (ii) ensuring confidentiality about DSR activations. The participation of consumers also enhances competition in the markets (balancing market, wholesale market…).

The central settlement model is **very good** in terms of **confidentiality**: the BRPs do not receive nominative information (aggregator, consumers) about DSR activations, but they need to receive aggregated information in order to ensure their missions. Indeed, BRPs are constantly monitoring their portfolio and making efforts to maintain it in a balanced position. If not informed of DSR activations, the supplier's BRP could counter balance it by reducing generation. In order to prevent this, the supplier's BRP needs to be duly and timely informed on the activated volume within its balancing perimeter. This requires specific modalities, put in place by the independent third party, to collect, aggregate, and transmit the information.

Implementation costs are **fairly well allocated**, being mainly supported by the independent third party (aggregator).

DSR energy invoicing

Efficiency

This model is **efficient**: the cost of activation for the consumer reflects the energy component of its supply price. Cost reflective DSR bids from the consumer itself or an aggregator on its behalf lead to an efficient arbitrage between market prices and usage value, without distortions in the merit order.

The costs are **properly allocated to the responsible actors**, and financial impacts on BRPs are neutralized since the transfer of energy is associated with a fair compensation to the BRP source or the supplier. It is supported by the consumer directly, since it is added on its energy bill. Then, these costs can be shared with the aggregator according to the agreement between the consumer and the aggregator.

Finally, it has a **positive impact on liquidity** in the wholesale market since it allows aggregators to add new bids corresponding to DSR products.

Implementability

DSR energy invoicing is **uneasy to set up**, as it requires heavy and complex evolutions of the market design. For suppliers, it may require the implementation of complex additional corrective processes for invoices, e.g. if taxation differs between consumed energy and the energy of DSR activations.

Its **complexity** also lies in the fact that transparency and confidentiality issues can lead to contradictory requirements, with diverging interests between BRPs and aggregators. A balance must therefore be found between those principles, to facilitate competition between aggregators and suppliers while preserving the fundamental role of BRPs in the market design. Trying to ensure both principles at the same time can rapidly increase the complexity of the associated market design.

Implementation costs are relatively higher than in other models, similarly to the case of the central settlement model, except that implementation costs due to financial flows management (between the aggregator and the supplier) are not supported by the independent third party in this model. Consequently, implementation costs are lower.

This model makes **little use of public funds**, as some costs could be borne by the independent third party, such as aggregation perimeters management, management and verification tasks.

Finally, the **scalability** of this model is **limited**: it only works for fine-tuned or telemetered consumers and is therefore not adapted to small consumers with index meters. It is compatible with existing cross-border solutions (the aggregator has however to be part of the portfolio of a BRP in the control area(s) where the load shedding takes places).

Fairness

Market designs without bilateral agreement **enable full competition** in the access to flexibility by (i) allowing aggregators to act without depending on supplying BRPs and (ii) ensuring confidentiality about DSR activations. The participation of consumers also enhances competition in the markets (balancing market, wholesale market…).

This model ensures a **good** level of **confidentiality** if supplier receives merged metering information, but is not totally ensured if the supplier receives separated metering information for the consumed energy and the energy of DSR activations from the metering entity.

Implementation costs are **fairly well allocated**, being mainly supported by the independent third party (aggregator).

7.4.3 Conclusions on the regulation of demand participation in short term energy markets

Table 21 synthesizes the previous analysis. Table 22 summarizes the assessment made of options with respect to efficiency, implementability, and fairness criteria. It also provides main arguments considered to support the assessment made of each option. As in the case of capacity and flexibility markets, the options analyzed here are not exclusive from one another, which makes the case for implementing all of them to leave DSR players with the widest possible choice.

In-portfolio options, where demand response is operated by the supplier, are of course the simplest arrangements, with a reasonably good economic efficiency in theory, but they enable no competition at all in the access to DSR-able loads as a resource. Having third parties entering in contract with the supplier to manage their portfolios is a step in the right direction but it does not fully solve the competition issue and it may create inefficiencies due to contractual conditions imposed by the supplier.

Finally, having an independent entity ensuring the settlement of the energy and financial transfers between the supplier and the aggregator and guaranteeing confidentiality is the most costly option but it enables competition in the aggregation market and, if DSR energy is invoiced, it enables a precise representation of the marginal cost of demand response, improving the economic efficiency.

Table 21: Summary of the assessment of options for organizing demand response in short term energy markets

		Implicit options		Explicit options		
		Variable supply price	Supplier load control	Bilateral agreement	Central settlement	DSR energy invoicing
Efficiency	Marginal cost reflectivity	Fair	Good	Fair	Good	Very good
	Cost causality	Good	Very good	Fair	Very good	Very good
	Liquidity	Poor	Poor	Very good	Very good	Very good
Implementability	Feasibility	Good	Good	Good	Poor	Poor
	Compatibility & simplicity	Very good	Very good	Fair	Poor	Poor
	Implementation costs	Good	Good	Good	Poor	Poor
	Level of use of public funds	Very good	Very good	Very good	Good	Very good
	Scalability	Very good	Fair	Very good	Very good	Fair
Fairness	Competition	Poor	Poor	Fair	Very good	Very good
	Confidentiality	Very good	Very good	Poor	Very good	Good
	Allocation of implementation costs	Good	Good	Very good	Fair	Good
	Level playing field for DSR	Fair	Fair	Fair	Very good	Very good

Table 22: Detailed summary of the assessment of options for organizing demand response in short term energy markets according to efficiency, implementability, and fairness criteria

	Efficiency	
Variable supply price	Good	The **consumer** arbitrates between retail price and its utility, but the arbitrage is imperfect if there is a discrepancy between wholesale and retail prices.
Supplier load control	Good	The **supplier** arbitrates between retail and wholesale prices: the consumer's utility is not taken into account in the supplier's decision to curtail.
Bilateral agreement	Fair	The supplier having a monopoly on DR of its consumers may lead to contractual conditions not reflecting well the marginal cost
Central settlement	Good	Economic efficiency is theoretically ensured if the price to settle the transfer of energy is cost-reflective. In this case the costs are allocated to the responsible players.
DSR energy invoicing	Very good	The cost of activation for the consumer perfectly reflects the energy part of its supply price: efficient arbitrage and allocation of costs to responsible players.
	Implementability	
Variable supply price	Very good	Bundled → very simple from a market design perspective; no public funds needed; scalable. Only requires multi-index meters.
Supplier load control	Good	Bundled → very simple from market design perspective; no public funds needed. But requires remote load control (industrial DSR only...)
Bilateral agreement	Good	The complexity is borne by the contracting agents. No public funds needed. Fit to all kinds of consumers since purely contractual.
Central settlement	Poor / fair	Heavy evolution in the market design, transparency and confidentiality costly to ensure. But no use of public funds, fit for all kinds of consumers.
DSR energy invoicing	Poor / fair	Requires complex evolutions of the market design; costly (confidentiality, transparency). Requires fine-tuned telemeters (not fit for residential consumers).

	(Fairness) Competition	
Variable supply price	Poor	Flexibility is directly valued through the supply contract, hence a monopolistic position of the supplier for the access to this flexibility.
Supplier load control	Poor	Flexibility is directly valued through the supply contract, hence a monopolistic position of the supplier for the access to this flexibility.
Bilateral agreement	Fair	Aggregators depend on the goodwill of suppliers to enter bilateral agreements. Increased competition on wholesale market
Central settlement	Very good	Aggregators act without depending on suppliers. Confidentiality about activation is ensured. Direct participation increases competition in WS market.
DSR energy invoicing	Very good	Aggregators act without depending on suppliers. Direct participation increases competition in WS market. Confidentiality about activation may be an issue

8 Conclusions

Achieving the appropriate functioning of the European electricity system in a long term future, driven by the massive use of renewable generation, will most probably require the modification of existing short term markets. These should increase their efficiency, robustness and achieve a high level of coordination both across Europe and across time, while encouraging the deployment and use of clean generation and the participation of demand.

Main required developments that are related to the functioning of short term markets, as analyzed in this report, are associated with the topics that follow:

1. Representation of the transmission network in short term markets,
2. Design of the sequence of markets,
3. Design of energy prices and format of bids,
4. Both the balancing service provision and the imbalance settlement arrangements in balancing markets,
5. Short term effects of the implementation of RES support schemes,
6. Design of mechanisms for the participation of demand in short term markets.

As far as the **representation made of the network** in markets is concerned, the preferred options are Zonal and Hybrid zonal pricing. The application of both of these should result in a large enough liquidity in markets, given the large number of active market players that should exist within price zones to be defined. Besides, the computational burden of computing the dispatch under both schemes should be small compared to that for other options like Nodal pricing. Given that infeasibilities resulting from the zonal dispatch should be limited, Zonal, and Hybrid zonal, network models could be considered as well in very short term markets. Prices computed are close to marginal supply costs under Hybrid zonal pricing, while they are less efficient under Zonal pricing. On the other hand, large experience exists about the implementation of Zonal pricing.

Other options that rank very high according to some criteria, like Nodal pricing under marginal cost reflectivity, perform poorly for other criteria. Thus, the liquidity of markets under Nodal pricing may be quite low in some areas, leading to the exercise of MP and non-reliable prices.

The **timing of markets** should be modified to allow their outcome to react faster to changes in system conditions largely caused by renewable generation. Then, day-ahead markets should be called as late as possible (regarding bid submission) while tasks associated with them should be carried out as quickly as possible. In the Intraday time frame, continuous trading, providing greater flexibility, should be implemented, while in those cases where flexibility is not enough this should be combined with discrete auctions.

Options for the procurement of balancing reserves from the long to the very short term should be made available to allow all types of resources to contribute reserves to the extent of their possibilities. Lastly, the gate closure should be taken as close as possible to real time, providing, again, more flexibility.

Regarding the **energy pricing and bidding protocols**, the EU approach turns out to be the most efficient, since prices computed more closely reflect marginal supply costs incurred. On the other hand, the US approach features more flexible bids that can reflect power plant constraints and provides larger certainty of producing a market price and a feasible market dispatch, which is not guaranteed under the EU approach. Given that both approaches have some advantages and disadvantages, preserving the EU approach within Europe seems sensible, thus avoiding large implementation costs, and major changes in market design, which would require a large consensus difficult to achieve.

As for **balancing markets**, a larger amount of competition would be achieved, if both capacity and energy products and upward and downward reserve are separately procured, all technologies are allowed to participate, minimum size requirements for bids are removed (or aggregation is allowed to take place) and pricing of products is marginal.

Regarding the imbalance settlement rules, if balancing arrangements applied are well suited to single pricing, this settlement scheme should allow prices to reflect the costs imposed on the system by any imbalance and should avoid creating a surplus for the system operator (SO) out of the application of the scheme. However, if balancing arrangements do not suit single pricing, this may produce worse results than dual pricing. The settlement period should be as short as possible for imbalances created by each agent to be reflected in payments to be made by it.

Lastly, imbalance actions should take place after intraday markets and the use of balancing resources for congestion management and balancing purposes should be kept separate regarding the price formation process.

RES support schemes applied should allow an effective and efficient functioning of short term markets. This is the case of long term clean capacity auctions, mainly, but also, to some extent, that of long term clean energy auctions, certificate schemes and FIP ones based on auctions. The distortion of efficient short term prices caused by long term capacity auctions is negligible, and it may be limited for the rest of these schemes. Being market schemes that make revenues of RES operators depend on operation decisions, these support options foster the participation of RES generation in short term markets and are difficult to manipulate by authorities. Lastly, Certificate schemes allocate the cost of RES support to agents responsible for the need to deploy this generation, i.e. consumers.

These are the preferred RES support schemes considering also their long term effects (see Market4RES deliverable D3.1), since they are effective in achieving the deployment of RES generation, and this should take place at a low cost, since also the long term signals they produce are efficient.

Lastly, regarding the **Participation of demand in short term markets**, all options available, both implicit and explicit schemes, should be allowed to provide consumers with large flexibility. Implicit schemes are the simplest ones and reasonably efficient. However, under these schemes, agents cannot compete to access DSR resources. Then, the implementation of independent load aggregators should also be considered an option. The transfer of funds between aggregators and suppliers should be set by an independent entity for the treatment to both of them to be fair and in order to promote efficiency in market functioning

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