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Electricity Market Functioning: Current Distortions, and How to Model Their Removal

FINAL REPORT

Berit Tennbakk, Arndt von Schemde and Daan Six.

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Internal Energy Market

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Preface

This report is the result of a cooperation between COWI Belgium, E3Mlab, EnergyVille, and THEMA Consulting Group, and the efforts of a large project team.

The following consultants and country experts have provided valuable contributions to the facts basis and the report:

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Oslo, 29 June 2016

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ACRONYMS

ACER – Agency for the Cooperation of Energy Regulators
aFRR – automatic Frequency Restoration Reserve
ATC – Available Transmission Capacity
BRP – Balance Responsible Party
CACM – Capacity Allocation and Congestion Management
CBCO - Critical Branches / Critical Outages
CHP – Combined Heat and Power
CM – Capacity Mechanisms
Commission – the EU Commission
CWE – Central West Europe
DAM – Day-Adhead Market
DC – Direct Current
DR- Demand Response
ENTSO-E – European Network of Transmission System Operators
EU – European Union
FAQ – Frequently Asked Questions
FBMC – Flow-based Market Coupling
FCR – Frequency Containment Reserve
FiT – Feed in Tariff
FiP – Feed in Premium
Fmax - Maximum allowable power flow
FRM – Flow Reliability Margin
GCC – Grid Control Cooperation
GSK – Generation Shift Key
IA – Impact Assessment
IC – Interconnector
IDM – Intraday Market
IEM – Internal Energy Market
MDI – Market Design Initiative
mFRR – manual Frequency Restoration Reserve
MRC – Multi-Regional Coupling project
MS – Member States
NTC – Net Transmission Capacity
PTDF – Power Transfer Distribution Factor
RAM – Reliable Available Margin
RES – Renewable Energy Sources
RR – Replacement Reserve
SoS- Security of Supply
TSO – Transmission System Operator
VoLL – Value of Lost Load
XBID – Cross-border Intraday project

EXECUTIVE SUMMARY

A central concern in the transition to a low-carbon electricity sector is to develop a new energy market design which accommodates the efficient integration of renewable energy sources, improves the market functioning and enhances overall investment signals. To this end, the Commission is currently in the process of developing a Market Design Initiative, which includes an Impact Assessment (IA) of various policy measures aimed at such an improvement of the energy market design.

In order to assess the impact of possible policy measures, it is necessary to take stock of the current situation, to identify relevant policy measures, and to find adequate ways of modelling the targeted distortions and the cost and benefits of removing them.

The study presented in this report has assisted the Commission in these areas. The focus of the study is on measures aimed at the day-ahead, intraday and balancing markets, although some other areas, such as G-tariffs, retail price regulation, hedging opportunities and capacity mechanisms are also touched upon.

The actual Impact Assessment modelling is not a part of this project, but both modelling issues and the identification of distortions and potential policy measures has been developed in cooperation with the Commission and the IA modelling teams.

Day-Ahead Markets

The Multi-Regional Coupling Project (MRC) implies that national electricity markets are coupled on the basis of single price market coupling with implicit allocation of cross-border interconnector capacity. Full price-coupling is implemented in South-Western Europe, North-Western Europe, and on the Italian borders, thus linking the majority of EU power markets[1], covering 19 European countries.

The facts show, however, that there are still several market design features in the day-ahead market (DAM) which potentially distort price formation and efficient trade:

- *DAM market design specifications:* Possible distortions are linked to the price caps, not allowing negative pricing, and shadow auctions. Participation from demand response is possible, but significant barriers still exist, for example related to product definitions.

- *RES support:* Schemes vary significantly among Member States and between technologies, both when it comes to support levels and exposure to market prices. This distorts the merit order curve and affects price formation. It could also lead to additional grid management costs.

- *Cross-border trade, interconnections and grid management:* Bidding zones are not determined from a holistic European system perspective. Curtailment practices are nontransparent and reported to possibly impact cross-border trade for 1/3 of MS. This is probably also related to distorting RES support schemes and priority dispatch. Generally, curtailment may not happen according to pure techno-economic criteria due to RES support design and priority dispatch rules. Calculation of interconnector capacities made available for DAM exchange, so-called ATC values, are in general not regionally coordinated.

[1] In addition, the same Price Coupling of Regions solution is implemented in the 4M market coupling area (Czech Republic, Hungary, Romania and Slovakia).

Intraday Markets

Intraday markets (IDM) are much less developed than day-ahead markets, and the extent of cross-border intraday trade is limited. The role of the intraday market is to make balance-responsible market participants able to correct deviations from the binding DAM production and consumption plan, via trade with other market participants who are able to increase or decrease their generation or consumption. Deviations from the DAM plan occur due to forecast errors related to the weather (wind, sun, temperatures) and due to incidents affecting generation and consumption.

The facts show that the liquidity of intraday trade is generally low in most of the 19 Member States where it is implemented, a fact that possibly to some extent can be explained by RES generators and demand-side resources not being balance responsible parties.

The following market design features may constitute significant market distortions when it comes to intraday markets and trade:

- *IDM market design specifications:* Gate closure times vary between markets, and so do price caps, while product definitions such as minimum bid sizes are mostly aligned with those of the DAM. Participation is for the most part open to all parties, but participation requirements and product definitions do not necessarily facilitate demand-side participation.

- *Cross-border trade, interconnections and grid management:* For a significant share of Member States, IDM cross-border trade only happens on an ad hoc basis, while three MS do not have IDM coupling at all. Non-transparent TSO practices imply that TSO re-dispatching can interfere with IDM trade and price formation.

Balancing Markets

The balancing markets are the TSOs' instrument to reserve and activate resources during the operating hour in order to manage residual imbalances in the system – i.e. variations during the operating hour or imbalances not handled by intraday trade. To this end, the TSOs need access to reserves, i.e. resources which can respond momentarily to maintain the frequency of the system, and reserves with response times from a few minutes up to 15 minutes or more. The practices of TSOs vary substantially between Member States when it comes to reserve procurement, sizing of reserves, remuneration, and exchange of reserves. It is sometimes difficult to obtain detailed information on these practices.

The facts indicate the following main distortions:

- *Balancing market design specifications:* The main distortions identified are related to participation requirements, with RES and the demand-side often not allowed to participate at all. To some extent resources are reserved on contracts with long-term obligations to supply balancing services, and not on a day-ahead basis. In some cases, provision of balancing resources is a technical requirement on some (thermal) units.

- *Procurement practices:* The volume of required reserves is defined by TSOs and the basis for the sizing is not always very transparent. Most TSOs apply specific time-tables for the procurement, though. Tendering mostly takes place on an annual, monthly or weekly basis. The remuneration is not always based on market bids, and sometimes pay-as-bid rather than pay-as-cleared.

- *Regional cooperation and coordination:* There is some bilateral exchange of balancing reserves (activation) between TSOs. There is also some experience with regional assessment of the need for reserves, but generally, the assessment is made by control area. There are no specific approaches for allocation of interconnector capacity for exchange of balancing reserves.

- *Curtailment:* TSOs employ involuntary curtailment of resources due to market and/or grid issues. While some TSOs curtail resources according to a specific order, in most cases the curtailment order is nontransparent or ad hoc.

Baseline for the Impact Assessment: The Distorted Scenario

As the baseline for the impact assessment of the possible policy measures, the following groups of distortions have been targeted:

- Lack of a level playing field for all resources in all market timeframes: All resources are not balance responsible, some resources have priority dispatch or are treated as must-run, there are significant barriers to participation for some resources in intraday and balancing markets (if participation is allowed at all).

- Inefficient price caps: Price caps vary to some extent between markets, and are to some extent set lower than the expected Value of Lost Load.

- Technical market design specifications vary: Technical requirements on market participation vary, and in particular represent barriers to cross-border exchange in intraday and balancing markets.

- Interconnector capacities are not optimally utilized: TSOs apply different rules for the calculation of ATC values, and the rules are not always transparent. As ATC calculations are not regionally coordinated, TSOs may tend to set too high security margins. Moreover, interconnector capacity is not optimally utilized across market timeframes. Cross-border intraday trade is limited and efficient exchange of balancing services across borders is still an exception.

- Suboptimal bidding zone delimitation: Only a few countries are divided into bidding zones reflecting bottlenecks in the domestic grid, and most bidding zones follow national borders.

- Sizing and procurement of balancing reserves: TSOs apply different practices for sizing and procurement of balancing reserves, and generally do not apply a regional approach.

- Barriers to demand-side participation: There are significant barriers to demand-side participation in most markets.[2] (The magnitude of distortions related to a lack of demand-side participation is analyzed in another study assisting the MDI IA.)

- Curtailment of resources: Curtailment of resources is often ad hoc or based on unclear rules, and not always carried out according to economic efficiency criteria.

It should be noted that the identified distortions are not present in all markets and that the status and practices vary substantially between Member States.

[2] The magnitude of distortions related to a lack of demand-side participation is analyzed in a parallel study on Downstream flexibility, price flexibility, demand response & smart metering, which is also part of the basis for the MDI impact assessment, conducted by Cowi, Ecofys, Thema and EnergyVille.

It is challenging to model the scenario with all these distortions, due to both data issues and technical modelling issues. It should be noted that all models are simplifications of reality, and the full complexity cannot be captured. Also, for some of the distortions, hard data is hard to come by. Nevertheless, modelling the distorted baseline scenario in a realistic, yet simplified manner, should provide a relevant basis for the assessment of the impact of the proposed policy measures.

Proposed Policy Measures

The impact assessment is to analyse the impact of implementing policy measures in order to remove the distortions. While the impact of some policy measures can be analysed one at the time, the impact is often affected by other measures as well, i.e. one distortions may best be reduced or removed by implementing several measures.

Broadly speaking, we have identified the following main areas that could be targeted by measures in order to improve short-term price formation and long-term investment incentives in the integrated European electricity market.

1. Measures to create a level playing field for all (relevant) resources

Creating a level playing field implies the removal of priority dispatch, imposing balance responsibility on all resources, while at the same time providing access to markets reduce or remove involuntary curtailment. This means that RES generation enters the market merit order, thus catering for more efficient price formation in the DAM and in existing intraday markets. As BRPs, RES generators get a stronger incentive to reduce forecast errors, to trade imbalances in the intraday market. Hence, the TSOs need to reserve balancing resources should be somewhat reduced. At the same time, RES resources can even be utilized for real-time balancing.

2. Measures to increase the efficiency of price formation in the market

The efficiency of price formation in the markets may be enhanced by harmonizing and increasing maximum price caps, thus catering for more efficient scarcity pricing and cross-border trade in the DAM. Maximum price caps should preferably be set at levels that incentivize scarcity pricing and demand side response, i.e. at least at the level of VoLL. Minimum price caps should also be allowed to be negative in order to cater for more efficient voluntary curtailment in surplus situations.

3. Measures to increase the ATC values made available for trade

ATC values may be increased by regional coordination of the calculation of ATC values, and by more efficient bidding zone delimitation. Transparent and coordinated ATC calculation can take advantage of all information available among the TSOs, including the interrelationship between flows on several interconnectors, and flows in the internal grids. Improved bidding zone delimitation is a related measure, where bidding zones are determined based on grid configuration and demand and supply patterns, rather than national borders. This measure should also enhance price formation and locational price signals in the day-ahead market, thereby reducing the cost of re-dispatching. The TSOs' need for balancing resources should hence also be reduced. As trade increases, price differences between markets should be reduced, and cross-border resources should be better utilized. This should in turn reduce the total need for capacity and increase the utilization of flexible generation.

4. Measures to facilitate and increase cross-border trade in intraday and balancing markets

Measures to accomplish increased cross-border trade in intraday markets, include harmonization of technical market specifications, including continuous trade, and allocation of available interconnector capacity to cross-border intraday trade. Markets can become more liquid by harmonizing rules for participation, gate closure times and product definitions. Increased liquidity in intraday markets should provide more efficient means of imbalance management by market participants prior to the operating hour, thus reducing the need for balancing reserves as well.

5. Measures to provide regional sizing and procurement of balancing resources

The need for balancing reserves may be reduced further by implementing regional reserve assessments and more efficient exchange of balancing reserves among TSOs. Measures to this end include regional assessment of the need for balancing reserves (coordinated sizing), harmonization of balancing products, and coordinated procurement and activation of balancing reserves across interconnect control areas or regions. Harmonized gate closure, product definitions and technical requirements are instrumental for the efficiency of such arrangements. By implementing regional assessments of reserve needs, the cost of balancing could be significantly reduced, in particular if other measures at the same time cater for participation of all relevant resource providers to the markets, cf. the measures described above.

6. Measures to increase the participation of demand-side resources

The increase demand-side participation should bring more flexibility into the market and in particular, contribute to more efficient handling of scarcity situations. Potentials and measures for demand-side response are analysed in more detail in the study referred to in footnote 2.

1. INTRODUCTION AND CONTEXT

1.1. BACKGROUND AND OBJECTIVE

In February 2015, the Juncker Commission announced that one of its main political priorities will be the implementation of the Energy Union strategy with a forward-looking climate change policy. This strategy envisions the delivery of the 2030 climate and energy targets while turning the European Union into a world leader in renewable energy. Achieving these goals will require a fundamental transformation of Europe's power system, including the redesign of the European electricity market.

A central concern in the transition to a new energy market design is the need to improve market functioning and investment signals in order to enhance power system and market efficiency, whilst at the same time seamlessly allowing for the integration of renewable energy sources in the system and in energy markets. The Commission believes that this will require a regional, cross-border coordination of policy making, system operation and infrastructure investments, ensuring security of supply and reflecting an integrated European approach. The European Commission's concerns about market distortions is also reflected in its communication on public intervention and the relation with the transition towards a single market, integration of renewables, integration of demand response, and mechanisms to ensure generation adequacy.

In order to advance the Energy Union, the Commission is currently reviewing the regulatory framework of the EU's electricity markets, in the so-called Market Design Initiative (MDI). The main objective of the Market Design Initiative is to ensure that the design of the Internal Energy Market (IEM) provides investments both on the demand and supply side in order to cater for long-term capacity adequacy. The objective implies efficient development of the EU electricity system, where investments take place at the right locations, while the wider energy policy objectives, such as electricity generation by renewable energy sources and energy efficiency targets are supported. Inherently, system efficiency includes optimal grid investments and utilization across Member States, and optimal utilization of flexible resources, also at the demand side. In order to enhance such market-wide long-term system efficiency, all stakeholders in the electricity system, generators, consumers, and grid companies, should face common and efficient short and long-term market prices, and unnecessary discrimination between resources should be abolished.

Specifically, the Commission aims at submitting a package of new legislative measures by the end of 2016. This package will include possible amendments to the internal market in energy legislation, to the Renewables Directive, to the Energy Efficiency Directive and to infrastructure regulations.

It is in this context that the Commission has requested assistance in the form of a study providing inputs to a so-called Impact Assessment, i.e. facts and data for the modelling of the impacts of removal of current market distortions. In order to assess the impact of various measures and regulations aimed at improving the market functioning, one needs to compare the market outcome in the distorted situation, i.e. under current practices, with the market outcome after the implementation of new legislative measures. The distorted scenario is based on the current situation and practices and forms the baseline for the impact assessment.

The main objective of the analysis in this project is:

- To provide an inventory of the market and regulation characteristics observed in the EU MS, backed up with available data and information

- To deduce from this inventory, the distortions that are likely to affect the results of the model simulations, with priority given to those distortions that could directly impact (market) incentives for investments and capacity adequacy

- To classify those distortions into generic categories in accordance with the nature of their potential impact on the market functioning, and suggest how those distortions can be represented or taken into account in electricity market and energy system models in general, and in the Commission's preferred modelling tools in particular

- To collect data which are necessary to quantify the stylised distortions by Member State

The focus of the present study is thus to provide insight and data input to the modelling of the distorted scenario, and to provide advice on the modelling approach to the distorted scenario. In performing the impact assessment, the Commission uses in-house modelling tools, namely PRIMES and METIS. Needless to say, the project has been carried out in close cooperation with the PRIMES and METIS modelling teams.

1.2. Approach

There is presently (still) an amalgam of market distortion factors in the EU countries that possibly affect investment signals, such as the presence of price caps in certain markets, discriminatory non-price based dispatch rules (e.g. based on fuel types), specific curtailment rules, support schemes (e.g. feed-in-tariffs), etc. The current situation, i.e. the market distortion factors, must be analysed properly, in order to perform a relevant Impact Assessment.

The present project has gathered information about the distortions in different market timeframes, i.e., distortions pertaining to in particular:

- The day-ahead market

- The intraday market

- The balancing market

- Capacity mechanisms

The focus of the study has been on market design features affecting market price formation directly, such as price caps and bidding requirements, and regulations and practices with an indirect impact, such as features distorting (mainly generation) dispatch, market coupling in different time-frames, utilization and allocation of cross-border interconnector capacity, and TSO practices regarding balancing procurement.

Issues related to imperfect competition due to market power have not been the focus of this study, neither has network tariffs, financial markets or retail markets. When it comes to the latter, we have however, also gathered some information, as they may have a significant impact on market prices formation as well.

The starting point for the analysis and the facts gathering has been a number of hypotheses on possible market distortions that could be targeted in the Market Design Initiative. In order to test the hypotheses, facts and data have been gathered on Member State level by a team of country experts. A common template was developed for this facts gathering, including guidance on the interpretation of the listed questions.

Based on the facts gathering, a selection of main distortions was derived as candidate targets for changes in the market design.

In parallel, the modelling of the distortions, and hence the modelling of the impact of removing them, was discussed with the modelling teams, including the modelling approaches, the interplay between the models, and the data needed for modelling the identified distortions and the impact of removing them.

The report is organized as follows:

- Chapter 2 presents an overview of the hypotheses and the gathered facts, a discussion of the impacts of the identified distortions, and the conclusion in terms of identified main distortions.

- Chapter 3 presents the distorted scenario, focussing on the modelling of the impacts of the identified distortions on the day-ahead market, the intraday markets and the balancing markets.

- Chapter 4 discusses the impact of the possible policy measures, and in particular how the market impacts and efficiency gains of different policy measures are related to each other.

The full country facts template in excel format accompanies this report.

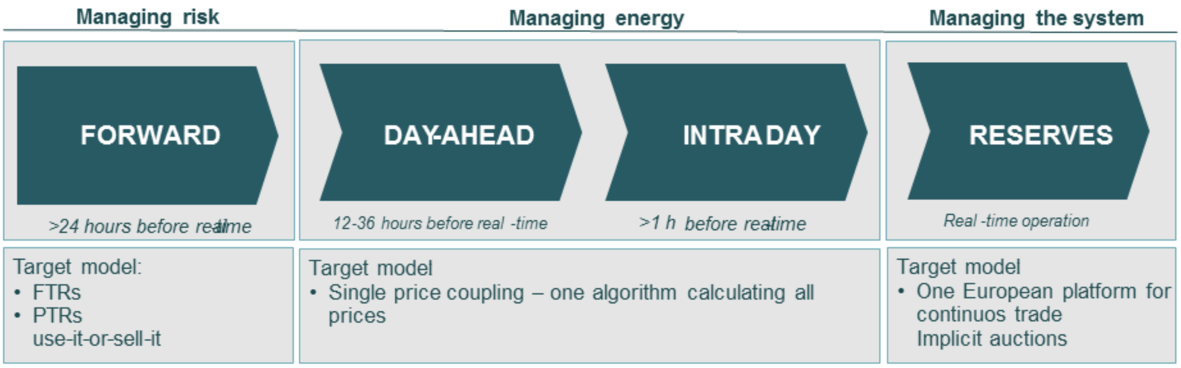
2. Status Overview – Gathered Facts

In the energy-only market design, the short and long term balancing (adequacy) of the market is supposed to be efficiently provided by the market mechanisms within the market frameworks. In practice, the responsibility is shared between the market participants, market operators and authorities, including system operators as regulated entities. From an administrative perspective, one might say that a large part of the planning of the system balance up to real time (the operation hour) is entrusted to the market participants, while the momentary balance is the responsibility of the TSOs (by delegation).

2.1. European Target Model: Interplay between Market Timeframes

Figure 1 below illustrates the relationship between the different market timeframes in a stylized energy-only market according to the European Target Model.

Figure 1 The EU target model for electricity markets



The physical exchange of power takes place in real-time, where generation has to equal consumption. For practical reasons, the time-resolution of the trades leading up to real-time, i.e. in the day-ahead and intraday markets, are made on an hourly or half-hourly basis. Since generators, providers of demand flexibility, and grid operators need to plan ahead in order to be able to strike the balance in real-time, there is a host of exchanges taking place before real-time. In many aspects, the day-ahead market plays a pivotal role in both long- and short-term planning.

Put simply, the day-ahead market solution constitutes a physically binding plan for generation and consumption for each trading period (hour or half-hour) for the next day. The plan is binding in the sense that it is the basis of a generation plan or planned consumption profile that is submitted to the TSO and is the basis for the TSOs planning of congestion management and reserve requirements.

The day-ahead plan is also binding in the sense that deviations from the plan imply a penalty (or a reward if the imbalance helps the system, depending on the specific balancing mechanism). The day-ahead bids, which form the basis for the market solution, are based on expectations for the next day. Forecast errors, e.g. regarding wind and temperature conditions, and outages of generation plants and in industry, imply that there will be deviations from the plan. Imbalances which occur during real-time operation must be handled by the TSOs. In order to handle such imbalances, the TSOs must have access to reserves that can change generation or consumption on short notice. The costs associated with the reservation and activation of reserves in balancing markets are borne by the market participants who are responsible for the imbalances.

Intraday trades, i.e. trades taking place between the day-ahead gate closure and real-time, allow the market participants to update plans and reduce real-time imbalance costs. The forecast error is likely to be reduced gradually as information is updated closer to the time of actual delivery (for both generation and consumption) and forecasts become more accurate. Liquid intraday markets provide the possibility for increased efficiency of the market balances: they allow for more accurate matching of supply and demand, closer to the time of delivery. At the same time, intraday trade does not require the same response times as pure TSO reserve products. TSO reserve products require that resources can ramp up and down on (very) short notice (for example, the activation time for automated frequency restoration reserves for instance varies between 2 and 15 minutes throughout Europe).

Trade in the different time-frames allows efficient utilization of generation capacity and demand side resources with different characteristics. Flexibility and capacity is rewarded in the day-ahead market through scarcity pricing, for its ability to adapt within different timeframes in the intraday market, and for rapid responses in the balancing markets. The cost of flexibility is expected to increases as we move closer to real-time and the shorter the notification time becomes. This is due to the different technical constraints of different flexibility providers. Resources which requires long notification times and slow ramping should offer their services in the intraday or day-ahead time-frame, whereas the most flexible resources should be utilized in the balancing time-frame. If the prices for flexibility are higher in the intraday time-frame than expected in the balancing time-frame, the most flexible resources should offer their resources in intraday, hence, subsequently equalizing the price difference between the markets.

For renewable generation, the market set-up should provide the opportunity to manage imbalances due to forecast errors at lower cost (competitive prices) compared to the imbalance settlement cost, and also to get paid for any flexibility that can be offered to the market. Similarly, demand should also be able to respond to market prices. Thus, scarcity pricing and price fluctuations, plus demand for intraday and balancing resources should stimulate and reward efficient demand response as well.

The provision of market prices based on marginal prices should also provide locational price signals and form the basis for efficient congestion management and trade between different areas. In order to manage bottlenecks in internal as well as cross-border interconnections, market prices should be adjusted so that prices in surplus areas are reduced and prices in deficit areas increased until the transmission capacity between the areas is not utilized beyond its maximum safe capacity. Thus, market prices should also reveal the marginal value of increasing the transmission capacity and thus, form the basis for efficient grid development. At the same time, area prices would signal the short and long term value of demand and supply in different areas, thereby stimulating increased demand and reduced supply in surplus areas, and reduced demand and increased supply in deficit areas.

The above paragraphs describe, in broad terms, the targeted European energy-only market design. However, the implementation of the model is challenged by evolving system dynamics and hampered by a number features which may lead to market distortions. In particular, the transition from systems dominated by large and relatively flexible conventional generation plants, to intermittent small-scale (distributed) renewable energy sources, reveals distortions that imply that all resources do not have equal access to the markets and that the resources are not optimally utilized within the currently implemented market designs.

In the following sections we elaborate on various crucial market design features for which the practical implementation may lead to distortions of the market functioning.

2.2. DAY-AHEAD MARKETS

The day-ahead market is the cornerstone of the European target model for electricity market design in the sense that day-ahead prices form the main basis for financial electricity trade, trade between market areas, retail prices, and the trade and price formation in intraday and balancing markets. Hence, inefficient price formation in the day-ahead markets implies inefficient price signals and investment incentives throughout the system. Therefore, in order to achieve the objective of the Market Design Initiative, it is crucial to remove market distortions in the day-ahead market.

There are several measures that could potentially reduce or remove such distortions. In this section we present some crucial design features and comment on the associated distortions. The discussion is based on economic market theory, and in particular the (normative) conditions for efficient price formation.

2.2.1. CRUCIAL MARKET DESIGN FEATURES

Compared to the other market timeframe segments of the European Target Model, the day-ahead markets have seen relatively good progress in terms of harmonisation and maturity. Regional market-coupling initiatives such as the Multi-Regional Coupling (MRC), see also section 2.2.1, have over the last years resulted in improved day-ahead market functioning.

An "ideal" day-ahead market could be conceived as highly liquid, transparent and harmonized (in terms of rules and products), with no entry barriers (non-discriminatory access of market participants at both supply and demand side). Furthermore, such an "ideal" market would not suffer from market power exercised by market participants, and fast and efficient market clearing algorithms should provide an optimal market outcome, ensuring he maximisation of social welfare on a European level, and taking possible grid constraints into account while providing efficient investment signals for generation, demand and infrastructure. In reality however, inefficient market design features and procedures are sometimes put in place in order to deal with grid constraints (e.g. interconnections), the possibility of reaching a non-optimal market outcome, the possibility of not reaching a feasible market outcome because of technical constraints and/or a lack of available physical units to match supply with demand, inflexibility, etc.

In what follows, selected crucial market design features are discussed which may be pursued by policy makers in order to further enhance the well-functioning of day-ahead markets on a European level.

Harmonized price caps

In a perfect market, supply and demand will reach an equilibrium where the wholesale price reflects the marginal cost of supply for generators and the marginal willingness to pay for consumers. If generation capacity is scarce, the market price should reflect the marginal willingness to pay for increased consumption. As most consumers do not participate directly in the wholesale market, the estimated marginal value of consumption is based on the value of lost load (VoLL). VoLL is a projected value which is supposed to reflect the maximum price consumers are willing to pay for the supply of electricity. If the wholesale price exceeds the VoLL, consumers would prefer to reduce their consumption, i.e. be curtailed. If, however the wholesale price is lower than the VoLL, consumers would rather pay the wholesale price and receive electricity.

Hence, efficient maximum price caps should not be set lower than the value of lost load (VoLL). The existing CACM regulation already requires harmonization of maximum and minimum price caps, and states that estimates of the VoLL should be taken into account. Estimating VoLL is however not an easy task, neither from a theoretical nor a practical perspective. Moreover, the VoLL probably changes over time and varies between Member States, time of day, year, etc. The most efficient way to reveal the value of lost load is through the market, i.e. letting demand respond to varying prices. If demand response is adequately represented in the market and can respond efficiently and timely to price variations, price caps could in theory be removed completely.

The marginal cost of supplying electricity differs between generators. In some cases, like for wind and solar generation, the marginal cost of production is close to zero. This means that the generators can accept very low prices and still earn a margin for the recovery of fixed costs. For other producers, such as thermal generation, the start-up costs can be higher than the variable production costs. If the wholesale price is very low in just one hour, it will be more profitable for the generators to continue their production rather than closing down and starting up again. As a result, the wholesale market can end up with oversupply in some hours, where prices should be allowed to be negative. In those cases, the producers will continue to supply electricity until the wholesale price is lower than the costs of shutting down production. Similarly, for the generation to start production for just one or a few hours, the wholesale price must be higher than the variable cost for such plant.

If the market is subject to a maximum price cap that is set below the VoLL, short-term prices will be too low in scarcity situations. Price caps below VoLL also implies that generation earn too low peak prices (not reflecting their marginal value) and that the incentives to maintain old capacity and invest in peaking capacity is muted. On the other hand, muted scarcity pricing may distort demand-side response in the market. Hence, too low price caps could have detrimental effects on the ability to handle scarcity situations, on the efficiency of price formation, and on market long-term investment incentives.

Moreover, if the price caps differ between the different markets, generators will have incentives to shift supply from one market to the other, and thereby reducing the long-term efficiency of an interconnected market.

In some cases, soft price caps can exist in the market even though it is not specified through official regulation. For example, if a TSO decides to use reserves or increase the available transmission capacity (ATC) of its interconnectors if it expects congestions, scarcity pricing (and locational price signals) may be muted. By increasing the ATC values in the day-ahead-market, the expected import from other price zones will increase which will reduce the wholesale price.

Similarly, minimum price caps can be too high. If the market design or algorithm do not allow negative prices, there might be situations with oversupply where the TSOs will need to curtail generation according to administrative rules rather than economic merit order. As the costs of starting up and shutting down varies between generators, it would be more efficient for the market to allow negative prices and thus stimulate reduction of supply from the generators that are facing the lowest start-stop costs.

Efficient Bidding zone delimitation

In most cases, the balance of electricity supply and demand varies between different areas within a country. In densely populated areas demand might be high, while there might be few local generators, making the area a net importer. The delivery of electricity is limited by the capacity of the grid and the transmission lines, and in some cases, demand for transmission capacity may exceed the supply and create congestions in the transmission grid.

In a perfect market, when resources are scarce, the price will increase so that the consumers that have the highest marginal willingness to pay, will receive the electricity. In the longer term, if generators see an area where prices are higher than the marginal cost of supply, they will move investments to that area to increase the profit margin. In the long term, when the area has attracted more investment, the scarcity will be reduced and so will the electricity prices, in theory to the equilibrium level where the generators earn normal market returns over time.

In most Member States, the current price zones reflect borders between control areas (usually national borders) and not structural (long-term) congestion in the grid caused by physical grid infrastructure limitations.

If an area suffers from congestion problems and inefficient dispatch, but is not able to transmit these issues through price signal to the end-consumers and local generators, the congestions have to be managed outside the day-ahead market. Even if the surplus situation is handled by efficient curtailment rules, the long-term price signals in the day-ahead market will be distorted.

With increasing shares of location-specific renewable generation (particularly wind) in the European power system, locational signals for consumers and not location-specific generation (i.e. power generation that does not rely on local energy sources and can chose their location in the grid) become even more crucial in order to minimize total system costs.

It is clear that insufficient bidding zone delimitation may potentially have a substantial negative effect on investments and system efficiency both in the short and in the long term, thereby possibly undermining the Internal Energy Market and contributing to the disintegration of markets. Creating bidding zones that reflect the congestions and scarcity of certain areas will improve market efficiency. In order to ensure implementation of adequate price zones according to techno-economic efficiency criteria, determining rules for efficient bidding zone delimitation should preferably be established from a common European systemic perspective in order to ensure optimality, efficiency and transparency.

Exposure of RES investments and operation to market prices

As most MS strive to reach the EU targets for renewable energy in 2020 and 2030, several support schemes have been developed to accommodate the implementation of wind and solar energy in particular. Examples of RES subsidies include feed-in tariffs, feed-in premiums, or green certificates. The result has been increased generation of renewable energy sources in the EU Member States.

The marginal cost of wind and solar is close to zero. This means that every wind and solar generator will try to deliver as much energy as possible when the wind is blowing and the sun is shining. Since the generation from renewable energy sources is mostly intermittent and less predictable than generation from conventional power plants, the TSOs face new issues regarding the balancing of the grid in real time.

From a system perspective, it can sometimes be economical to reduce the generation of wind and solar in order to maintain the system balance. However, if RES generation is paid a feed-in premium when market prices are negative, it will not have an incentive to stop generation until the price is negative by the same numerical value as the subsidy. If it receives a fixed feed-in tariff, it has no incentive to reduce generation at any market price. In other words, the subsidy implies that even when market prices are negative, the RES generation may earn a positive revenue.

Exposing RES generation to market signals also implies making RES generation balance responsible parties. Balance responsibility is expected to stimulate more accurate forecasting, increased trade in the intraday market – which implies that new information appearing before IDM gate closure is utilized and reflected in the market – and subsequently lower TSO balancing costs.

Moreover, locational price signals should also reach RES generation in order to signal the true marginal value of the specific generation. By exposing RES generation to locational price signals, investments should, to the extent possible, be directed towards deficit areas instead of towards surplus areas. Hence, the value of RES generation will be higher, and the cost of accommodating RES generation will be lower, including grid costs.

Non-discriminatory dispatch rules or practices

Basically, all resources should be remunerated in the market on equal terms. This does not mean that all resources should earn the same revenues, but that different resources face the same prices for equal services. TSOs should dispatch generation according to the market merit order, and handle technical restrictions and deviations in other market timeframes.

Priority dispatch implies that TSOs are obliged to schedule and dispatch energy from some generators before others, i.e. not according to the merit order. Priority dispatch can be considered an indirect support mechanism, and has often been implemented in order make sure that electricity generation from renewable energy reach the market.

Other technologies than RES generation might be subject to priority dispatch as well. Examples include biomass plants, plants using indigenous resources and cogeneration plants. Such positive discrimination for indigenous fuels and renewable generation is permitted under the third energy package, for renewables even under the renewables directive, and for cogeneration under the energy efficiency directive. Discrimination may take the form of explicit priority dispatch, but could also result from exemptions from technical requirements and/or balancing costs, and exemption from participation in re-dispatch.

As merit order dispatch minimizes system costs, priority dispatch increases total system costs by increasing the costs for the TSOs, i.e. balancing costs, re-dispatching costs and curtailment compensation. Priority dispatch implies that the cheapest resources are not used to balance supply and demand, and to handle deviations and system imbalances. Hence, priority dispatch distorts price formation in all timeframes.

Participation open for all relevant resources

All relevant resources should be allowed access to the markets. By relevant resources we mean resources that may provide valuable services (e.g. flexibility) to the system at competitive costs, including also transaction costs.

Traditionally, wholesale markets have been designed to accommodate conventional generation capacity, and this may still be reflected in product definitions and technical and economic requirements on market participants. As other generation technologies enter the market, and new technologies becomes available for the management of electricity consumption, the traditional wholesale market design may have to change in order to accommodate and exploit these new, and partly distributed resources. For example, the minimum bid size may exclude load and certain storage resources from participation, in particular if aggregation of bids is not permitted.

Allowing small-scale producers and consumers to participate in the market, e.g., through aggregated bids, creates incentives for demand side response and flexible solutions, thereby potentially creating a more dynamic market. New flexible resources can be made available in all market timeframes. Hence, reforming the market design by taking into account the different characteristics of different resources which may contribute valuable services to the system, is potentially an important piece of the effort to accomplish an efficient energy transition. The impact from unconventional generation capacity might be small at this point, but it is likely to increase in the future.

Exclusion of resources also increase system costs, as similarly to priority dispatch, it implies that the cheapest resources are not always used to balance supply and demand, and to handle deviations and imbalances.

Limited curtailment and re-dispatch outside the market

Priority dispatch may in practice imply that some resources cannot be used by the TSO in necessary re-dispatching of the system, i.e. priority dispatch can prevent curtailment of e.g., renewable resources, even when this is the most cost-effective measure from an overall system cost point of view. In particular, as long as the price zone delimitation is inefficient, such priority can potentially imply substantial costs.

Increasing the number of price zones to take structural grid congestion into account and exposing renewables to market prices, should reduce the negative impacts of priority dispatch post the wholesale market. However, even if adequate price areas are defined, the TSOs will probably still need to use re-dispatching in order to balance the system and handle within-zone and temporary congestion from time to time. Such needs should preferably be handled via balancing markets, however.

Mitigation of market power

Market power should be mitigated for a number of reasons. In particular, when it comes to price formation in scarcity periods, market power can be exploited to effectively deter investments. In principle, incumbents can drive up scarcity prices. This should, in the absence of entry barriers, attract new investment, but at the same time, the presence of dominant suppliers introduce uncertainty about future price formation for potential entrants. The risks related to volatile and unpredictable future prices probably already constitutes a significant barrier to investment for new entrants.

In many cases, the risks associated with market power have been used as the rationale for price caps in the market. Hence, if price caps are increased or removed, there is also a stronger case for stricter market monitoring and tools to mitigate market power. At the same time, facilitating increased demand side participation should also effectively mitigate market power.

Implementation of flow-based market coupling

Flow-based market coupling (FBMC) implies that the market solution takes physical power flows into account more efficiently than traditional solutions based on ex ante and not always well-coordinated ATC/NTC estimates.

Electricity trade in the DAM solution has to take the technical characteristics and limitations of the grid into account in an efficient manner. In order to avoid overload on congested interconnectors (including internal lines), the TSOs in implicitly integrated markets (without FBMC), currently determine the maximum volume that can be traded on a line by setting ATC values as a priori restrictions in the price-coupling market algorithm. However, the actual flow on a line and the capacity utilization depends on total flows in the grid. The expected flows can deviate substantially from the flows associated with the DAM solution, and with the flows in real-time.

The idea behind FBMC is to include the physical flows in the market algorithm, utilizing the grid more efficiently by taking the actual bids and resulting flows into account. Moreover, the FBMC algorithm also takes the interrelationship between flows on different lines into account. In turn, the TSOs may allow higher flows on individual transmission lines, because of smaller deviations between market flows and physical flows. In addition, internal bottlenecks within a country can be accounted for in the flow-based market algorithm.[3]

In comparison to ATC calculations, the FBMC algorithms excels at defining the physical power flows and identifying bottlenecks. If the TSO fails to set the ATC values correctly, the grid is likely to be under-utilized or the re-dispatch costs will be high. FBMC implies more efficient dispatch and more efficient utilization of interconnectors and the internal grid. FBMC thus also affects market prices, and provides improved locational price signals. All of these elements will improve market efficiency and reduce welfare losses.

The full potential of FBMC is however, not realized if structural bottlenecks (critical branches) are not reflected in prices, i.e. without corresponding bidding zone delimitation. In the latter case, although price formation is improved, the locational price signals are still muted, and so are the long-term locational investment incentives.

Regional ATC calculation

In general, it should also be possible to improve the utilization of interconnectors by coordinating ATC calculations across larger regions, and across price areas, and not only according to borders between control areas, thereby taking the interrelationship between flows on different interconnectors better into account.

Increased coordination amongst TSOs is likely to improve the efficiency and reduce deadweight losses as a result of ATC values that are set too low.

Utilize interconnector capacity according to DAM prices

In order to maximize social welfare and reduce overall costs, efficient trade is important. Trade in the electricity market is limited by interconnector capacity between market areas. In order to maximize the value of the interconnectors, the capacity should be made available to the short-term markets and trade should follow price differences between the different areas.

This implies, e.g., that no capacity should be sold in long-term auctions without effective use-it-or-lose-it clauses. The owner of an interconnector or a transmission right has the right to the congestion rent. The interconnector capacity is optimally utilized if trade is determined by short-term price differences. Optimal trade caters for efficient utilization of cross-border resources. However, optimal trade does not maximize congestion rents. Therefore, private holders of transmission capacity will not have incentives to utilize the capacity in an efficient manner, unless the opportunity to restrict trade is limited.

In principle, the interconnector capacity should be split along the market time frames according to the highest value of trade. The difference in timing is however a

[3] http://www.thema.no/wp-content/uploads/2015/05/THEMA-Insight-2015-6-Flow-Based-Market-Coupling.pdf

challenge. While the DAM solution reflects the expected value of trade in all hours for the next day, the value in the intraday and balancing market is not known ex ante. If one wants to make sure that capacity is available for IDM and BM exchange, some capacity must be reserved for these markets prior to DAM gate closure. Hence, allocation along timeframes must be based on expectations and predictions. If the predictions are very inaccurate, and if such reservation is fixed for longer time periods, the value of reservation may quickly become very low or negative. Hence, the design of models for reservation of capacity across timeframes should be made with care.

The current rules state that reservation is only permitted if it can be clearly demonstrated that such reservation improves social welfare. This is a sound principle that should be maintained.

However, after DAM gate closure, cross-border IDM trade in the opposite direction of the DAM solution should be made possible, even if the line is congested according to the DAM solution. If trades are made in the opposite direction in the IDM, capacity is then also freed up for IDM trades in the same direction as the DAM solution. Making such reallocation possible, should improve IDM efficiency and reduce balancing costs for market participants. If trade in the IDM is continuous, the IC capacity available could also be updated continuously.

Shadow auctions

Certain market clearing algorithms call market participants to resubmit bids if the initial bidding does not provide a market clearing price below a certain threshold. Such practices may constitute soft price caps, and may also invite gaming, in which prices are implicitly "coordinated" to the level just below the shadow auction trigger prices.

The reason for the shadow auction rules may be to reveal and be able to correct errors in the registration of bids or the market algorithm itself, but that should not be a reason to invite all market participants to submit new bids.

2.2.2. STATE OF PLAY

2.2.2.1. Regional initiatives

Before elaborating on the findings with respect to the day-ahead market, as well as for the intraday market in the next section, a few notes should be made on the European Target Model for future market design as introduced in the previous chapter. More specifically, the Regional Market development is of primary relevance, as it comprises regional market-coupling initiatives (at both the day-ahead and intraday level) in order to achieve a European Internal Energy Market[4], and explains the levels of harmonisation already achieved.

A harmonised approach to the day-ahead electricity market organisation is pursued by the Multi-Regional Coupling Project (MRC). In the MRC, national electricity markets are coupled on the basis of Single Price Market Coupling with implicit allocation of cross-border capacities. By doing so, the day-ahead market has become the largest and most liquid market.

[4] https://www.entsoe.eu/Documents/Events/2014/141013_ENTSO-E_Update-on-IEM-related%20project%20work_final.pdf

On 13th May 2014, full price-coupling of the South-Western Europe (SWE) and North-Western Europe (NWE) day-ahead electricity markets was achieved, covering at that time 17 European countries.[5]

On 19th November 2014, the 4M Market Coupling project was launched, integrating the markets of Czech Republic, Hungary, Romania and Slovakia.[6] The 4M Market Coupling uses the same Price Coupling of Regions (PCR) solution as applied in the other European regions and prepares the ground for smooth future integration of the Central Eastern Europe region and the rest of Europe.

On 24th February 2015, the Italian Borders Market Coupling (IBMC) was implemented.[7]. By doing so, the Italian-Austrian, Italian-French and Italian-Slovenian borders were coupled with the Multi-Regional Coupling (MRC), thus linking the majority of EU power markets, covering 19 European countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Great Britain, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland (via the SwePol Link), Portugal, Slovenia, Spain and Sweden).

Finally, another milestone was reached by the successful implementation of the Flow-Based methodology in the CWE Day-Ahead market coupling on 20th May 2015. The Flow-Based methodology is a more sophisticated method for capacity calculation and is considered to increase price convergence compared to ATC-based methods, while ensuring the same security of supply as before.

More information on the actual status of regional initiatives can be found in the ACER Regional Initiatives Status Review Report 2015.[8]

2.2.2.2. Results

It is important to stress that the described results below are based on the observations from the countries for which information was available. As can be seen in the template that was filled out by the country experts, there was not always information available for all market features and their related questions.

DAM market specification

The Scandinavian countries (Nord Pool) and Italy, Spain and Portugal tend to have relatively high traded market volumes on the day-ahead segment, i.e. roughly > 75 % of total consumption or generation, while in other European countries, the average relative traded volumes are more in the order of up to 40 % of total consumption/generation. Note that for certain countries like Croatia and Bulgaria, the DAM power exchange was launched rather recently.

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5 http://www.belpex.be/press-releases/south-western-and-north-western-europe-day-ahead-markets-successfully-coupled/

6 http://www.belpex.be/uncategorized/4m-market-coupling-launches-successfully-by-using-pcr-solution/

7 http://www.belpex.be/press-releases/italian-borders-successfully-coupled/

8 http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Regional%20Initiatives%20Status%20Review%20Report%202015.pdf

Price caps

Price caps in the day-ahead segment are defined for all observed countries where information was available. The reasons for these price caps are often not clearly indicated, but in general it comes down to a combination of the following reasons: alignment with coupled power exchanges, guaranteeing performance of the power exchange clearing algorithms and assumptions on reasonable cap levels based on observed historical data.

Figure 2 below provides an overview of the caps on maximum prices in the observed MS. The results indicate a high level of harmonization amongst the majority of the countries with a maximum price cap above 3000 €/MWh which functions more as a technical constraint rather than a market distortion. In some countries however, especially Portugal, Spain and Greece, the maximum price is set at a fairly low level which may distort cross-border price signals.

Figure 2 Overview of maximum prices in the day-ahead market

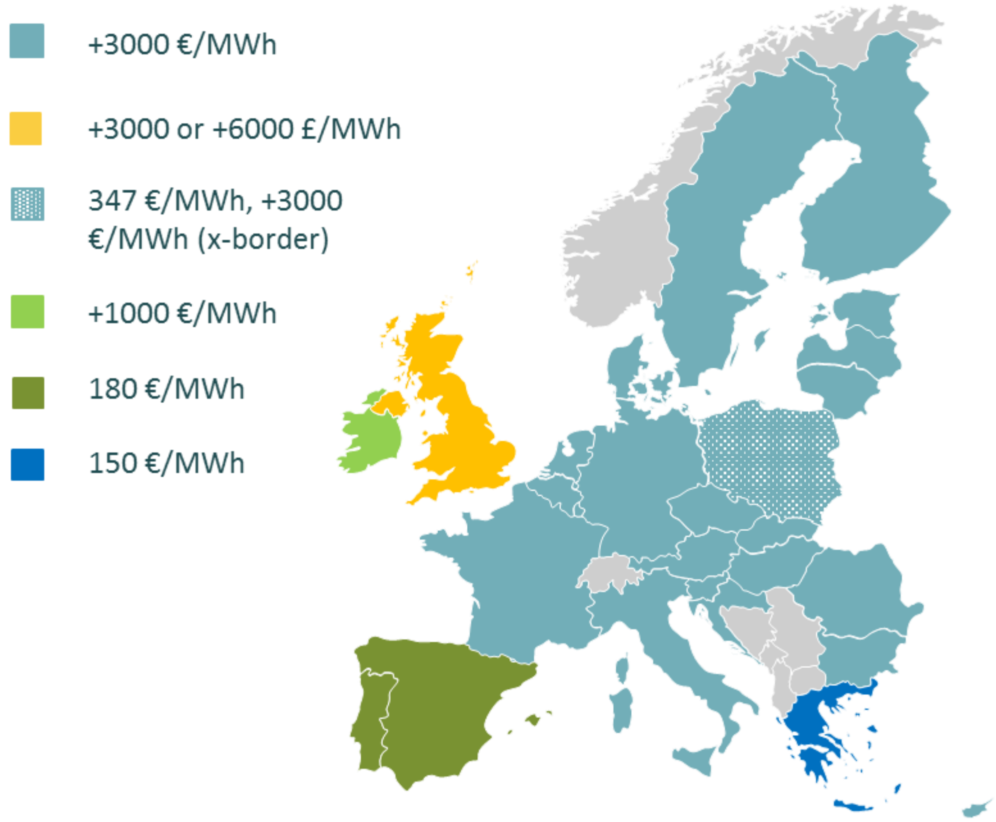
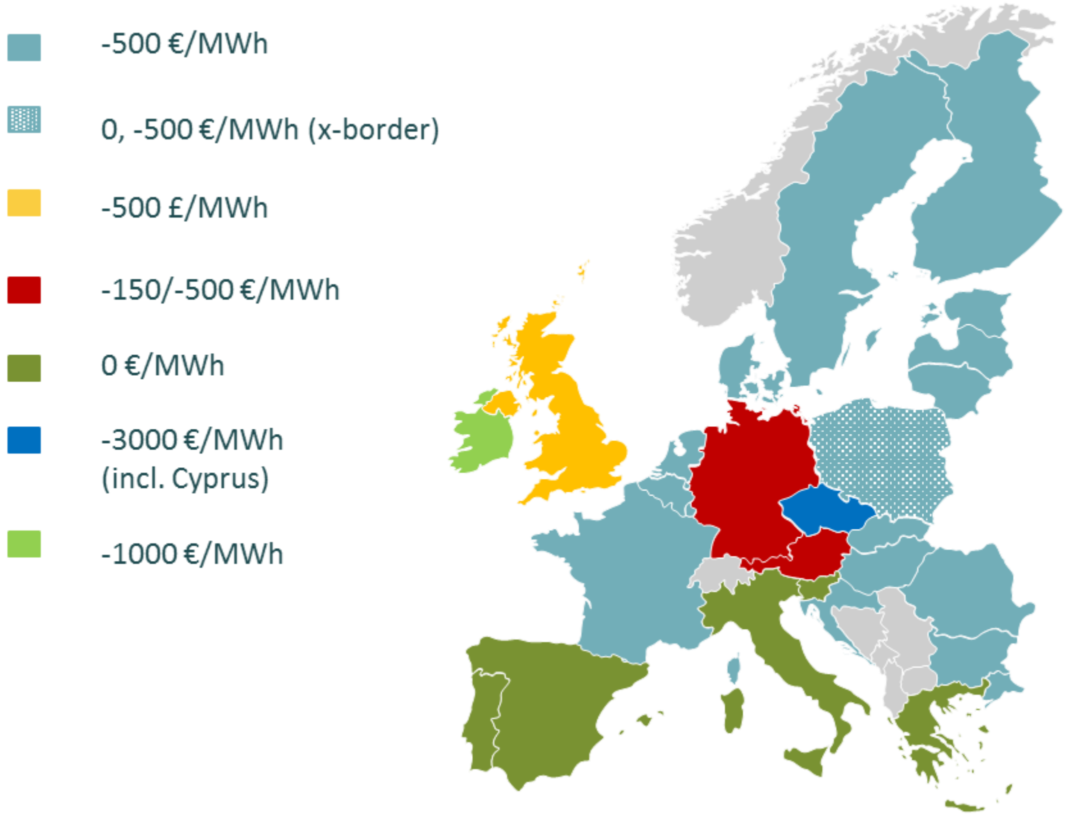


Figure 3 shows an overview of the minimum prices in the selected countries. Again, most of the countries are subject to a common minimum price of -500 €/MW. Some countries do not operate with negative minimum prices i.e. Spain, Portugal, Greece, Slovenia and Italy, while Poland only operates with a minimum price for cross-border trading and a price of 0 €/MWh for internal trading.

Figure 3 Overview of minimum prices in the day-ahead market



Shadow auctions

For approximately 1/3 of the EU MS, a threshold market clearing price is determined within the market clearing algorithm for triggering potential shadow auctions. The trigger for these shadow auctions might find their origin in abnormal prices due to either technical issues during the execution of the market clearing algorithms, or bidding behaviour of market participants.

For those countries, the values are +500 €/MWh or -150 €/MWh (except for UK where the thresholds are +500 £/MWh and -150 £/MWh). The procedures and values are transparent and publicly available.

The practice of using shadow auctions in 30 % of the observed MS could possibly constitute a market distortion, creating soft price caps and inviting selective bids in the auctioning process.

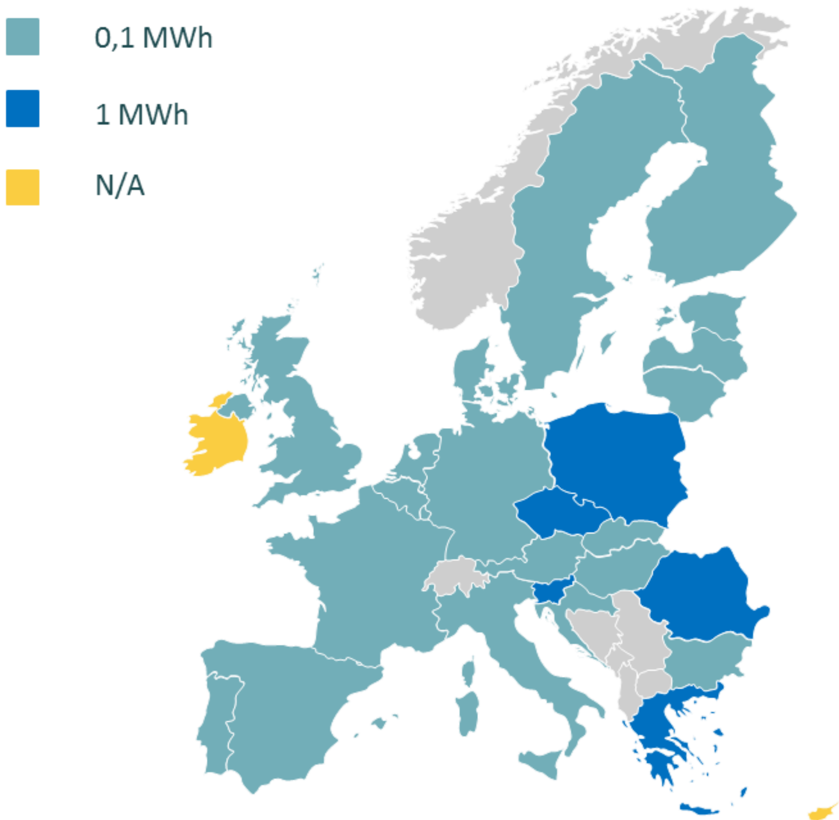
Minimum bidding sizes

Figure 4 displays the minimum bidding sizes used in the MS. The most common granularity of bids is 0,1 MWh (except for Greece, Slovenia, Poland, Romania, Czech Republic: 1 MWh).

As can be derived from the template, all MS allow at least hourly bids, as well as block orders. In addition, the majority of the MS involved in the MRC also allow some kind of smart or flexible orders, allowing more flexible/intelligent bidding into the market.

Another observation relates to the fact that in all MS portfolio bidding is implemented, except for Greece, Ireland, Portugal and Spain, who apply variations of unit bidding.[9]

Figure 4 Overview minimum bids in the day-ahead market



Demand response participation

Although there is little information available on the actual participation of demand response in the market[10], demand response can implicitly participate in most of the MS through the aggregated bidding by a supplier/BRP. France has implemented a particular mechanism (NEBEF) to allow demand response to be bid into the market by a third party, different from the energy supplier.[11] The results indicate that there are still efficiency gains to be had by improving demand response participation in most European countries.

RES investments and operation

Support schemes

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[9] Portfolio bidding means that the organized market output does not induce automatically any piece of a generators' program (unit commitment) to be taken into account by the TSO. The bids are not linked to specific generating units. The organized market physical output is then a clearing balance that the portfolio is committed to include in its final imbalance settlement. In other words, all the unit commitment is done by portfolio managers separately from (and after) the organized market clearing.

Unit bidding means that each bid must be linked to a specific unit (generation or load) and the organized market physical output translates directly into the programs for generators and loads.

[10] See for instance: http://www.smartenergydemand.eu/?p=6533

[11] https://clients.rte-france.com/lang/an/visiteurs/vie/nebef_presentation.jsp

The template for the EU MS clearly shows that there is a wide variety and diversity of support schemes for RES that may have an impact on their actual responsiveness to market prices. Those support schemes are very country specific[12] and even within MS, there are possible differences (e.g. on a regional/province/municipality level) in how RES is supported.

Trying to summarize the main types of support schemes in clusters of countries carries the risk of oversimplification. Nevertheless, here are some observations:

- Spain is currently the only country where no RES support is in place. In the past, Feed-In-Tariffs and Feed-In-Premiums were applied, but currently RES-support is blocked for all new installations. This could possibly be linked to the fact that excess generation is already experienced.

- The value of RES support is very diverse across Europe and over time, and mostly technology-dependent. Estimated/reported values vary between 0 and 450 €/MWh.

- The following types of RES support schemes are currently in place in one or more EU MS:
  - Investment grants
  - Feed-In-Tariffs
  - Feed-In-Premiums
  - Market based mechanisms such as green certificates
  - Tax regulations
  - Net metering
  - Specific loans

Priority access and priority dispatch

The gathered facts show that priority of connection and dispatch is a common feature for several member states.

- About 25 % of the EU MS offer priority of connection for RES technologies

- About 40 % of the EU MS offer priority dispatch for RES

- In about 25 % of the EU MS, RES generation benefits from some form of favourable exemption (e.g. auto-consumption, balance responsibility)

- Possible specific curtailment rules apply in 40 % of the EU MS but do not specifically relate to negative prices. Curtailment decisions are mostly based on technical criteria (grid issues) although the occurrence of negative prices, as well as curtailment might in certain countries come with some kind of compensation for subsidies or missed production.

In approximately half of the EU MS, a form of priority dispatch for RES was reported. In up to 7 MS, some, although limited, information was found in which exemptions were mentioned for specific technologies.

[12] For Cyprus and Malta, no information was found.

With respect to particular restrictions for certain power producing technologies on the amount of electricity that they can produce, following observations can be mentioned:

- In Austria, nuclear energy is not allowed to be used for production of electricity.[13]
- In Denmark, wind support schemes assume a maximum number of full load hours.
- In Greece, there are limitations imposed on thermal power plants.
- In Ireland, no more than 50 % of generation can be supplied by non-synchronous generation units.

<u>Internal congestion management</u>

Bidding zones

In almost all EU MS, there is one bidding zone, with the following exceptions:

- 2 bidding zones in Denmark, Greece[14] and Luxembourg. In the UK, discussions are ongoing to move from 1 to 2 bidding zones.
- 4 bidding zones for Sweden
- 6 bidding zones for Italy

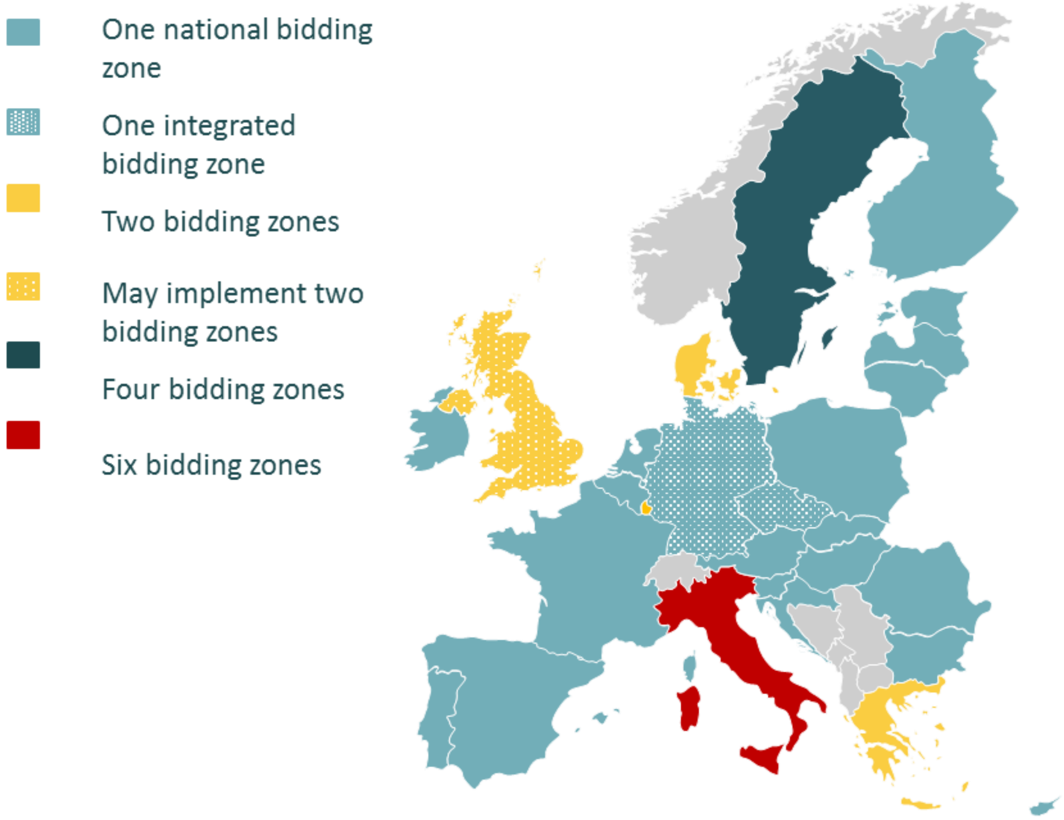
Germany and Austria is currently one integrated bidding zone (since 2002), but this set-up is currently under discussion as physical flows between Germany and Austria frequently exceed capacity and create loop flows.

The underlying reasons for the determination of bidding zones is mostly purely geopolitical. For the countries with more than one zone, this was decided because of structural bottlenecks in the grid.

[13] Note that in countries like Germany and Belgium, also a nuclear phase out is foreseen in the coming years.

[14] In case of a north-south congestion, generation is paid according to the zonal marginal price, whereas loads pay the calculated system price (weighted average of zonal prices).

Figure 5 Overview of bidding zones in the day-ahead market



Curtailment/ re-dispatch

With respect to the re-dispatching rules for internal congestion management, it is observed that in half of the MS no internal re-dispatching issues are reported, or information about the rules and practices is not available.

For the countries where some information could be obtained, the re-dispatch rules are determined primarily by the concerned TSO and based on techno-economic assessments, although information is often difficult to find or not really transparent. For some MS, some publicly available information could be found (e.g. Austria, Germany, Netherlands, Portugal, and Spain). The transparency dashboard of ENTSO-E[15] gives some indications on re-dispatching activities.

Impact on cross-border trade

For about 1/3 of the countries, possible impacts on cross-border trade was reported.

In general, only fragmented pieces of information on the actual re-dispatch costs and prices could be found.

[15] https://transparency.entsoe.eu/dashboard/show

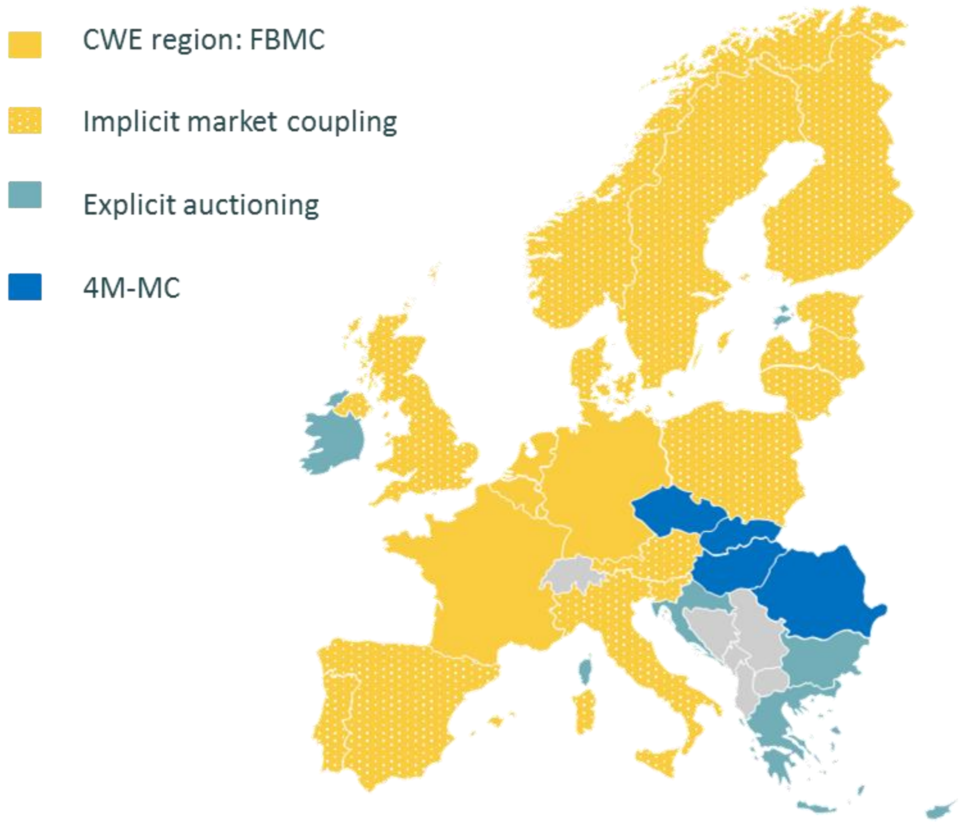
<u>Market integration and trade</u>

Flow-Based Market Coupling

The majority of the EU MS are implicitly coupled in the day-ahead timeframe through the Multi-Regional Coupling Project as explained before.

In the countries of the CWE-region (Belgium, Netherlands, Luxembourg, France, Germany), Flow-Based Market Coupling is applied since 2015, while in approximately half of the EU MS, market coupling is implemented through ATC calculations. The results are displayed in Figure 6.

Figure 6 Overview of day-ahead market coupling



ATC calculation

Within the CWE region, Flow-Based Market Coupling based on the Euphemia algorithm has been applied since 2015. For about 30 % of the EU MS, the ATC values are calculated according to the ENTSO-E procedures (see also the network code on CACM). For the remaining countries, the information could not be found or the calculations are arranged between TSOs without specifying the exact procedure. In total, for approximately 40 % of the EU MS, some more or less transparent method could be found or derived.

Market power mitigation

For all EU MS[16], the country experts reported that market power is somehow monitored. In half of those countries, potential market power issues were observed, mainly related to high levels of market concentration.

Priority curtailment and re-dispatch post wholesale market

No specific information on priority curtailment and re-dispatch could be found for 75 % of the EU MS. In the remaining 25 % of observed countries, some form of priority is given to RES-based technologies.

Allocation of interconnector capacities in DAM and other timeframes

For about half of the EU MS, there is an ex ante split in the allocation of interconnector capacities along different timeframes, mostly through yearly and monthly auctions, before the implicit or explicit allocation on day-ahead or intraday takes place.

2.2.3. MAIN DISTORTIONS

The facts show that there are still several market design features in the day-ahead markets which potentially distort price formation and act as possible barriers to efficient trade.

The identified possible market distortions can be clustered roughly in 3 areas:

- *DAM Market Design:* possible distortions that are linked to the way power exchange platforms are set up, trade products are defined, market participation is organised, etc.
- *RES support:* possible distortions for which the cause can be rooted back to supporting mechanisms for RES resulting in certain (in)direct market effects
- *Cross-border trade, interconnections and grid management:* distortions originating from imperfect interconnections, bidding zone determination and market coupling, as well as grid operation practices

The assessment is summarized in the following table, in which also an indication is made to what extent the distortion was identified as main distortions in this study because of it expected possible impact on the market.

[16] For Cyprus and Malta, no information is available.

Table 1 Identification of main distortions in the day-ahead market

Market design feature	Comment	Main distortion?
DAM market design		
Price caps	Generally set at technical levels which are unlikely to affect price formation. However, in some MS the price caps are fairly low, and some MS do not allow negative prices. This could limit the effect of market-based signals to the market participants and thus limit incentives for market-based behaviour and investments. Too high minimum price levels, increasing the use of involuntary curtailment.	Yes
Shadow auction	Employed by 1/3 of the MS: Shadow auctions which are triggered by price levels lower than the technical caps and allows the market participants to re-submit bids, can give rise to market distortions in terms of strategic behaviour. Purely technical issues encountered during market clearing can be identified during the process and do not necessarily require re-submission of the bids by market participants. Proper power market monitoring and simulations could follow up possible deviating market behaviour.	Possibly
Minimum bidding size	Largely harmonized	No
DR participation	In most MS, DR participation is possible, but mostly indirectly through BRPs. Market products were historically designed from a static generation and consumption perspective. The specific development of products designed for DR and storage has the potential to lower entry barriers and allow for more non-discriminatory access of different technologies to the market, thereby increasing market efficiency and reducing costs.	Probably
RES support		
Support schemes	Vary significantly within and between MS, both when it comes to designs and support levels, and the exposure to market prices. Several RES support schemes directly or indirectly distort the merit order (FiT, FiPs, etc.), which in turn could lead to suboptimal market results and additional grid management costs (balancing and re-dispatching).	Yes
Priority dispatch	Certain technologies are subject to priority dispatch, priority of connection and favourable exemptions in half of MS. Similar to support schemes for RES, priority dispatch distorts the merit order and could result in (hidden) additional costs in terms of grid management.	Yes

Cross border trade, interconnections and grid management		
Bidding zone delimitation	Mainly set according to MS or control zone borders, not necessarily optimized from a holistic European power system perspective.	Yes
Curtailment	Mainly related to grid issues but could also be linked to balancing challenges. It is hard to find detailed information and evidence, although possible cross-border trade impacts were reported for 1/3 of MS. This possible distortion relates to grid management challenges which might be in turn originate from other market distortions such as RES support and priority dispatch. Curtailment an sich might not be a distortion, distortions occur if curtailment does not happen according to the actual cost of the action (merit order).	Probably
Market coupling	Most markets are implicitly (price) coupled in DAM, i.e. trade happens according to hourly price differences. Further market integration and harmonisation is expected.	No
ATC calculation	Approximately 30 % of MS are reported to calculate ATC values according to ENTSO-e procedures, while for the remaining MS, ATC values are bilaterally agreed between TSOs. In general, there seems to be a lack of regional coordination for determining ATCs in an optimal way. In-optimal ATC calculation, in particular too low ATC values (too high security margin) reduce trade and impact market price formation. Flow-based market-coupling should increase trade flows, but is currently only implemented in CWE.	Probably

2.3. Intraday Markets

The role of intraday markets is to contribute to efficient handling of imbalances by activating responses to changes in market plans between DAM gate closure and real-time operation.

As explained in section 2.1, the DAM solution constitutes a binding plan for generation and consumption for all hours in the following day (for the balance responsible parties). After gate closure in the DAM and before the real-time operation takes place, a number of reasons may cause market participants to need or want to change their production or consumption plan. New data on wind conditions, changes in temperatures, failures in generation plant, are examples of such changes.

Deviations between the market plan and the actual generation or consumption (in real-time) must be handled by the TSOs, by means of resources available in the balancing markets. The costs of doing so (reservation and activation of balancing resources) is allocated to the participants who cause the imbalances. The intraday market provides market participants with an opportunity to update their plans when they realize that deviations will occur. This means that they can use the intraday market to “rebalance” their portfolio before the real-time operation hour. They will have an incentive to do so, if they expect the cost of trade in the intraday market to be lower than the imbalance cost imposed by the TSO.

It follows from the above that if imbalances are handled in the intraday market, the volume of reserves required by the TSOs will be lower. There are two main reasons for this:

- More resources are made available for balancing, as balancing can be provided by resources with longer notification times and lower ramping rates, compared to the requirements of TSO balancing products.
- The balance responsible parties get a stronger incentive to be active in the intraday market, thus reducing the imbalances that the TSOs must handle.

2.3.1. Crucial Market Design Features

In order to make sure that the intraday market functions well within and across Member States, a number of design features are important. These are elaborated in more detail below.

Within member states

Crucial market design features include amongst others:

- Participation should be open to all – no entry barriers
- Price caps should preferably be removed or set at least as high as in DAM
- Ensure that TSOs reservation and activation of balancing reserves does not distort price formation in intraday markets

A well-functioning, liquid and efficient intraday market requires that market participants have easy access to the market and that they have proper incentives to participate. As in the DAM, unnecessary obstacles to participation, such as too high minimum bidding sizes, and unnecessary technical and economic requirements, should be identified and removed. On the other hand, minimum bidding sizes and standardizing products are necessary in order to keep transactions costs down and to create liquidity. In order to facilitate participation of smaller-scale flexibility, the possibility of allowing aggregators to represent and aggregate smaller generation and/or loads should be investigated. This is important to provide all relevant flexible resources with incentives to participate, and at the same time to provide BRPs with the best possible opportunities to minimize their balancing costs.

The balance responsibility is obviously important for the incentives to trade in the intraday market. Market actors who are not balance responsible do not carry their own imbalance costs, and thus have weak incentives to participate in the intraday market. Balancing of intermittent and less predictable RES generation could for example become costlier from a systemic point of view if the imbalances have to be handled by means of the TSO's flexibility products, which have to be activated with shorter notification times.

For the same reason as in the DAM, i.e. efficient price formation, price caps should be set at levels which do not hinder scarcity pricing or facilitates price collusion. Moreover, continuous trade should also cater for optimal use of the flexible resources, as market participants can act on new information as soon as it is revealed. In addition, moving gate closure closer to real time, should also cater for more efficient solutions and use of flexible resources, increasing the opportunity to handle deviations in the market, rather than by TSOs.

It should be noted that although intraday markets and balancing markets are not directly overlapping, some of the flexible resources can be traded in both market timeframes. Flexible resources can be used by the BRPs to handle imbalances before real-time, and by TSOs to manage grid constraints (avoid constraint violations) and to handle residual imbalances in the operating hour. Hence, there is a competition between the TSOs and market participants for flexible resources available after the DAM gate closure. A provider of flexibility will offer his services in the market where he expects to realize the highest price. A provider with very high flexibility, may offer his services in the FRRm market. However, if he expects to realize higher prices in the intraday market, he will offer his services there instead. Hence, price formation in the intraday market and in the balancing markets are related.

At the same time, some resources may only be able to offer their flexibility in the Intraday time-frame, depending on the product definitions in the balancing markets. This is due to the fact that some providers can offer flexibility that can be activated on very short notice, while others need longer notification times. Thus, the intraday market may offer opportunities to trade other products than the balancing markets, and to utilize flexibility resources which are not necessarily suitable for the balancing markets.

The TSO may reserve capacity for provision of balancing flexibility, in which case, these resources may not be available for the intraday market (depending on requirements – balancing resources may also be allowed of update their bids and offers in the balancing markets if they chose to strike trades in the intraday market). However, even if TSOs reserve capacity for balancing bids, the flexibility providers will choose what market to bid their flexibility in according to the prices they expect to achieve.

Flexibility which may commit to the provision of flexibility on long-term contracts and flexibility with short notification times is likely to realize a higher value in the balancing market than in the intraday market, where it competes with flexibility that can be provided on a more ad hoc basis and perhaps also needs longer notification times.

In theory, leaving enough flexibility options in the intraday framework to the market participants should enhance the market outcome efficiency and, again in theory, it would be ideal if the market can freely play in both the DAM and ID timeframe before re-dispatching and re-balancing is conducted by TSOs, assuming that the installed mechanism for doing so can react quickly, efficiently and effectively to induce the required re-dispatching actions in time. If TSOs reserve too much capacity for real-time balancing, this could drive up reservation prices and reduce activation prices in balancing markets, thus reducing the incentives to use the intraday markets.

Across member states

The generation and consumption patterns differ between MS according to the generation mix, renewable energy sources and differences in energy consumption. Different market areas have different access to flexible resources, and flexible resources are vital to the cost-efficient integration of renewable electricity generation. By facilitating the exploitation of flexible resources over larger market areas, the total system costs can be reduced, including the balancing costs of renewable electricity generation, and the value of flexibility is enhanced. This implies that intraday prices in different markets can be very different. Hence, the value of cross-border trade in intraday products can be substantial.

Efficient cross-border intraday trade requires

- Harmonized market rules and design
- Access to cross-border transmission capacity

In order for intraday markets to be integrated across markets and control areas, the market design, including gate closure times, mode of trade (continuous versus discrete) and product definitions should be harmonized.

Ideally, interconnector capacity should be utilized for exchange of the most valuable products. As the DAM solution is subject to the available interconnector capacity, however, cross-border intraday trade requires either that capacity is reserved for intraday trade, or that capacity that is not used by DAM is made available for intraday trade. Reserving capacity ex ante, i.e. prior to DAM gate closure, is tricky, as the assessment of the value for intraday exchange has to be based on expected intraday price differences.

Obviously, if the interconnector capacity is not fully utilized in the DAM, residual capacity could and should be made available for intraday trade. It should also be noted that even if the DAM solution implies that an interconnection is fully utilized for imports or exports, cross-border resources can be used for intraday trade in the opposite direction of the DAM flows. And once an exchange has been made, capacity is freed up and this capacity can be used for intraday trade in the DAM flow direction as well. Continuous trade ensures that the interconnector capacity can be used optimally (is re-optimized) throughout the intraday trading period.

2.3.2. State of Play

2.3.2.1. Regional initiatives

In comparison to the day-ahead market framework, progress within the intraday area suffers from much more issues and difficulties and the current status is much less mature.[17]

Just like coupling the day-ahead markets, coupling national intraday (ID) markets would have the advantage of increased intraday liquidity for the benefit of all market players, and would support a better integration of renewable energy sources. The rules for a continuous intraday market are set out in the CACM network code and would allow market participants to trade energy close to real time (up to roughly one hour ahead of delivery).[18] The most important project related to the intraday target model is the Cross-border intraday project (XBID project), which would allow continuous implicit trading across France, Belgium, Luxembourg, Netherlands, Germany, Switzerland, Austria, GB, Denmark, Sweden, Finland, Norway, Austria, Portugal, Italy and Spain. According to the current plans, the XBID project is supposed to go live in Q3 2017.

2.3.2.2. Results

It is important to stress that the described results below are based upon the observations in countries for which information was available. As can be seen in the template that was filled out by the country experts, there was not always information available for all market features and their related questions in the intraday segment.

<u>*Market design*</u>

Mode of trade

From the answers of the country experts, it can be observed that 19 EU MS have implemented an intraday market. For 14 of those countries, the intraday market has continuous trade, 3 countries have a discrete intraday market (Italy, Spain, Portugal), while in Germany and Austria, there is both continuous trade and discrete auctions available to market participants.

In addition to the 19 countries above, 4 EU MS have concrete plans for the implementation of an intraday market (Croatia, Ireland, Hungary, Slovakia).

Gate closure times

The gate closure times vary between 1 hour and 5 minutes before the time of delivery, with the exception of Poland (3,5 hours before time of delivery).

Price caps

In terms of price restrictions (caps and floor), the diversity is much bigger than in the day-ahead market segment. Figure 7 displays an overview of the price caps in the IDM. While most countries have price cap levels that are unlikely to create market

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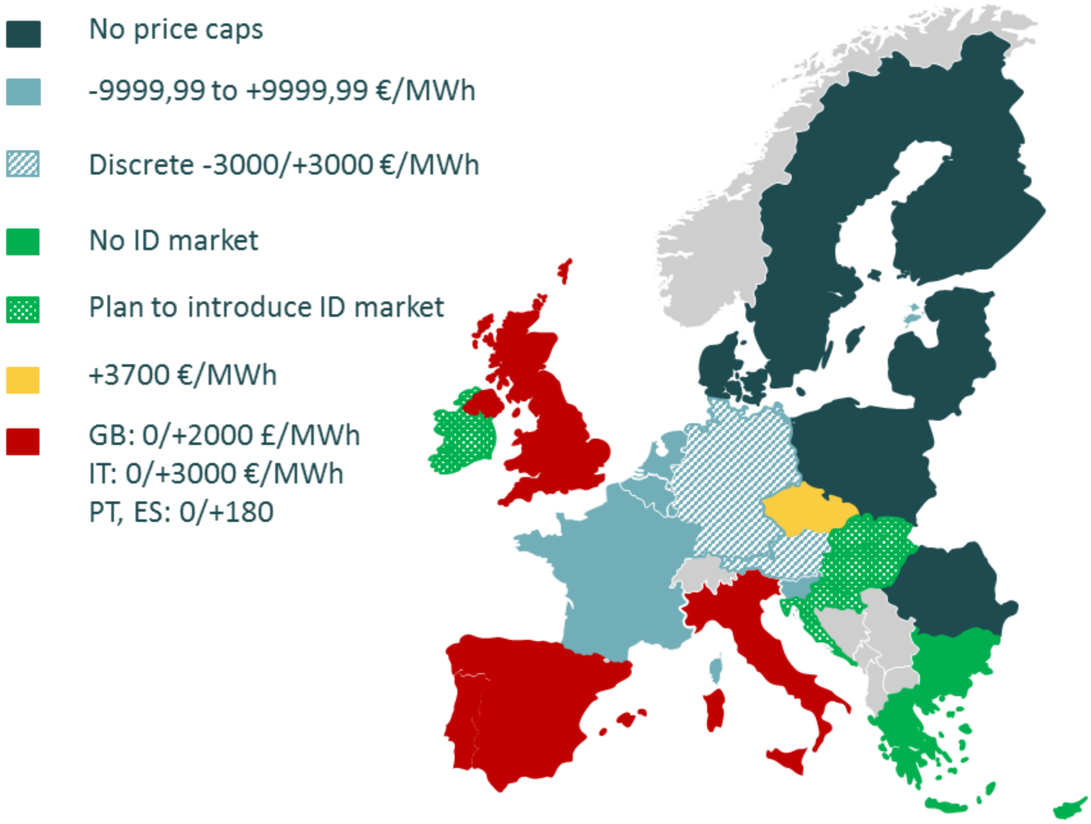
17 http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Regional%20Initiatives%20Status%20Review%20Report%202015.pdf

18 https://www.entsoe.eu/Documents/Events/2014/141013_ENTSO-E_Update-on-IEM-related%20project%20work_final.pdf

distortions, a couple of countries operate with lower caps, such as Portugal and Spain, and/or without negative prices, such as Great Britain and Italy.

Figure 7 Overview of price caps in the Intraday markets

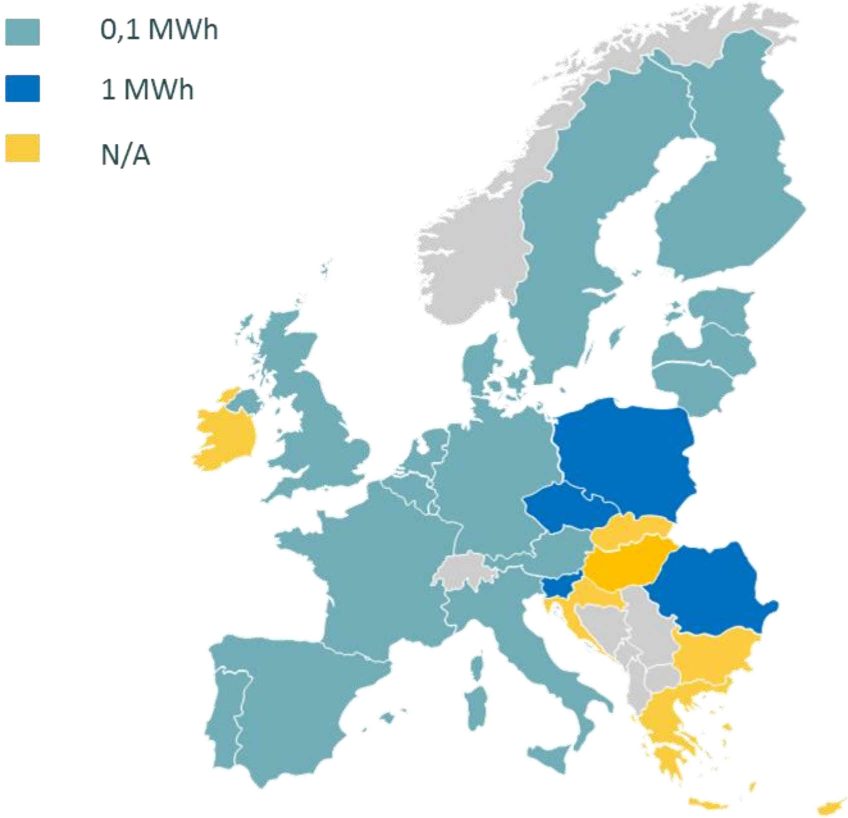


Minimum bid sizes

With respect to the minimum size of bids on the intraday segment, it can be observed that they are on country level mostly aligned with the day-ahead market, resulting in bid sizes of 0,1 MWh or 1 MWh, see section 2.2.2.2. Note that Greece does not yet have an intraday market, but plans to implement one in the near future.

The figure below summarizes the requirements for minimum bids in the IDM per Member State.

Figure 8 Overview of minimum bids in the Intraday markets



Participation

As can be derived from the facts template, the countries with an intraday market in place mostly allow different sorts of orders, being single 15' orders, hourly orders, as well as (standardized and/or user-defined) block orders. Execution conditions mentioned by the country experts are: Fill, All-or-Nothing, Fill-or-kill, Immediate-or-Cancel, Iceberg Order, Block Order.

In the majority of the intraday markets (16 of 28 countries), aggregation or portfolio bidding is allowed. In Ireland, generators are subject to unit bidding. In Spain, Romania, Portugal and Poland, unit bidding is applied.

Apart from registration at the market place and balance responsibility, no special requirements are imposed to market participants. No dedicated demand response products were identified by the country experts, which means that indirect demand response participation is still possible within the portfolio of a supplier or other BRP.

In terms of liquidity, the volumes traded in the intraday markets are naturally much lower than the volumes traded in the day-ahead, as the intraday trade mainly address deviations from the DAM plan. Compared to the demand level, volumes are generally (well) below 10 % of the demand with the exception of Spain (12%). It is hard to determine what volume would be sufficient to say that the market is sufficiently liquid as it depends on a number of other market features which vary between countries.

<u>*Market coupling*</u>

Mechanism

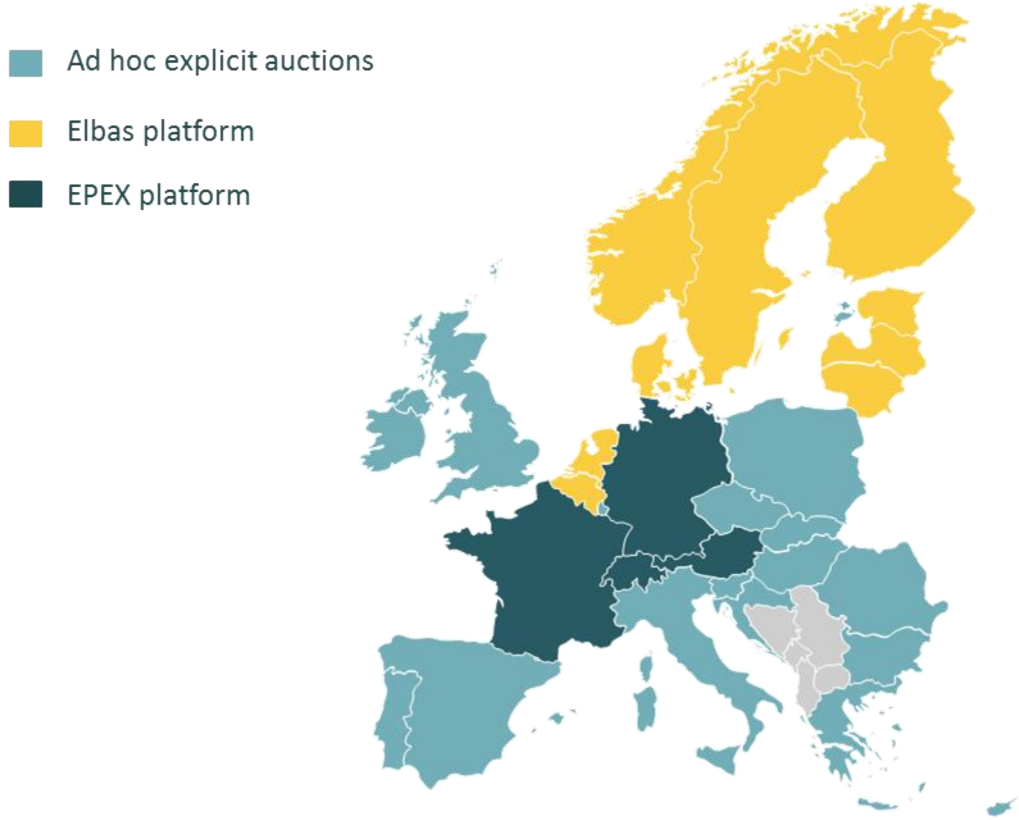
With respect to market coupling, the XBID project, as introduced in section 2.3.2.1, is expected to play an important role in the coming years. Up till now, market coupling initiatives are rather ad hoc and consist of both implicit and explicit auctions through different platforms. The lack of coordination between markets is likely to cause market distortions.

The EPEX platform, as shown in Figure 10, couples the intraday segments of Austria, Germany, France and Switzerland while the Elbas platform (Nord Pool) couples the following countries: Netherlands, Belgium, Denmark, Sweden, Norway, Finland, Estonia, Lithuania, Latvia. In those cases, implicit coupling takes place by showing the bids that are available; the bids behind grid bottlenecks are not shown.

For three countries, no coupling of intraday markets with neighbouring countries was observed by the country experts: Romania, Poland and Great Britain.

For the remaining countries with an intraday market in place, ad hoc explicit auctions are available for certain of their neighbouring countries, e.g. Belgium with France, Austria with Italy, Hungary, Czech Republic, Slovenia, and Switzerland, etc.

Figure 9 Overview of Intraday market coupling



IC allocation

For 16 countries, the country experts reported the possibility to reallocate IC capacity for cross-border intraday market trade. The available capacity in those countries is determined by TSOs after the previous timeframe of the market, possibly in cooperation with a particular auction office, where applicable.

TSO activation of re-dispatch

On the question when TSOs starts with re-dispatching actions, the country experts were able to retrieve very little information.

2.3.3. MAIN DISTORTIONS

A significant number of MS (eight) have not implemented intraday market trade, although implementation is planned in five of them. In the countries where an intraday market has been implemented, liquidity generally appears to be quite low, although it is not obvious what would be the proper indicator for sufficient liquidity. Nevertheless, low liquidity is an indicator that the market is not functioning adequately.

Market coupling is not wide-spread, although more or less organized cross-border coupling and exchange does exist. However, the XBID project is expected to increase and improve intraday market coupling.

The identified possible intraday market distortions can roughly be clustered in 2 areas, similar to the Day-ahead market distortions:

- ID Market Design: Possible distortions that are linked to the way power exchange platforms are set up, trade products are defined, market participation is organised, etc.

- Cross-border trade, interconnections and grid management: Distortions originating from imperfect interconnections, bidding zone determination and market coupling, as well as grid operation practices.

Note that possible exemptions of RES for balance responsibility might also affect their (non-) involvement in the intraday timeframe.

The assessment is summarized in the following table, in which it is also indicated to what extent the distortion was identified as a main distortion based on its expected impact on the market.

Table 2 Identification of main distortions in the intraday market

Market design feature	Comment	Main distortion?
IDM market design		
Mode of trade	Most MS where an intraday market is implemented, have continuous trade	No
Gate closure times	Most GCTs vary between 1 hour and 5 minutes before delivery. The closer to real time, the more interesting this market could be to adjust market positions without having the need to rely on the balancing mechanism and resources contracted by the TSO.	Possibly
Price caps	A significant diversity in price caps between different MS was observed. Price caps might hinder the "right" price formation, and hamper efficient cross-border IDM trade.	Probably
Minimum bid sizes	The minimum bid sizes in the intraday market are mostly aligned with DAM.	No
Participation	Aggregation/portfolio bidding mostly allowed, DR can participate indirectly through BRPs. Similar to the DAM, but less mature, intraday market products were designed from a static generation and consumption perspective. The specific development of products designed for DR and storage has the potential to lower entry barriers and facilitate access of different technologies to the market.	Possibly
Cross-border trade, interconnections and grid management		
Mechanism	For a significant share of MS, market coupling is organized only according to ad hoc explicit auctions on some interconnections, while three MS do not have IDM coupling at all. A higher level of market coupling and cross-border trade is expected to increase market liquidity and market performance.	Yes
IC allocation	In most MS, it is possible to reallocate capacity not used in DAM.	No
TSO procurement and activation of balancing resources	For most MS, the precise practices of re-dispatching actions by TSOs are not available in a transparent way. Moreover, re-dispatch actions can interfere with the intraday market depending on the timing of contracting and activation of flexible resources, as well as depending on the contractual conditions (including remuneration).	Possibly

2.4. BALANCING MARKETS

The overall objective of the market design for balancing markets is to make sure that sufficient balancing resources are available in the very short timeframe, that balancing prices reflect the cost of providing flexibility, and that markets are cost-efficient and take advantage of cross-border flexibility resources. Thereby, the balancing costs can be minimized and the TSOs' need for balancing reserves can be reduced as real-time imbalances are also kept at a minimum, because the market participants have the opportunity to trade themselves in balance before real-time operation.

As explained above, the TSOs need resources to balance the system in real-time, with respect to imbalances caused by deviations to the plans submitted by market participants (DAM solution adjusted by intraday trades), in order to balance variations during the operation hour (could also be half-hour or quarter depending on the imbalance settlement period), and to manage grid congestions and unforeseen events in real-time. Balancing services are divided into different products, depending on their purpose. ENTSO-E has defined a set of standardized products, with the purpose to harmonize product definitions across Member States.

- Frequency Containment Reserves (FCR), "the active power reserves available to contain system frequency after the occurrence of an imbalance", which is automatically activated, and also known as primary reserves. The response time is typically seconds.

- Frequency Restoration Reserves (FRR), "the active power reserves available to restore system frequency to the nominal frequency and […] restore the power balance to the scheduled value". FRR is either activated automatically (aFRR) or manually (mFRR) after FCR is activated, and is also known as either secondary and/or tertiary reserves. The response time is a few minutes for aFRR and 10-15 minutes for mFRR.

- Replacement Reserves (RR) is "the active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including operating reserves".

In brief, FCR is used to ensure the stability of the system at any point of time, whereas FRR and RR are used to handle (energy) imbalances, when there is a mismatch between the market commitments of BRPs and their actual load or generation. Note that not all FRR and RR products are used by all TSOs.

Balancing markets concern both the *reservation* of balancing services (reserves), and the *activation* of such reserves when needed. A TSO may reserve capacity for each of the different products in advance, in order to make sure that sufficient reserves are available during the operating hour, with some kind of payment (set through an auction process, or as a regulated price), or simply impose an obligation to be available to provide reserves on some generators. The activation of the reserves depends however on the imbalances during the operating hour. The activation may follow the merit order of a set of activation (energy) bids.

As argued in section 2.3 above, the more efficiently imbalances are handled by BRPs prior to real-time, i.e. in the DAM solution and via intraday trade, the lower the balancing costs, and the more efficient the utilization of flexibility resources. It is however also important that the TSOs use balancing markets in a way that does not distort price formation in the intraday market, and that the imbalance settlement properly incentivizes BRPs to manage imbalances in the market.

By facilitating efficient intraday markets and incentivizing BRP balancing via transparent market platforms, plus by sharing balancing resources across control areas, the total volume of balancing reserves needed by the TSOs should go down. At the same time, more flexibility resources are made available to the wholesale markets (DAM and IDM) and the combined flexibility resources can be used more efficiently, thereby increasing social welfare. (Balancing in the intraday market does not merely imply that flexible resources are moved from TSO balancing to market balancing, but even that more resources can be available for balancing as intraday trade does not have to adhere to the stricter product definitions of TSOs' balancing markets.)

Balancing markets should be open to all participants who are able to provide relevant balancing services. Moreover, the TSOs should, when technically possible, share balancing resources in order to reduce volumes and costs, and in order to use flexibility resources efficiently across control areas and bidding zones.

2.4.1. CRUCIAL MARKET DESIGN FEATURES

A number of market design features affect the efficiency of the balancing markets, some of which are commented below and for which the current status in the Member States have been surveyed in the project.

Technical market specifications

The balancing market takes over responsibility when the intraday market is closed. Providers of flexibility as well as BRPs are likely to adjust their portfolios according to upgrade information and according to the price of balancing in the intraday market and the price of balancing in the balancing markets. Hence, there will be arbitrage between the markets, taking into account the increasing technical requirements for resources as the operating hour approaches, and the uncertainty on balancing needs. By moving gate closure as close to real-time as practically possible, this arbitrage opportunity is kept open as long as possible, more of the balancing is left to the market, and less intervention should be needed by the TSO (except the real-time balancing within the operation hour to maintain a stable system frequency). Again, this should reduce balancing costs and increase the utilization of available flexibility resources.

For the same reason as in the DAM and IDM, price caps should be set at levels which do not risk muting scarcity pricing.

The product definitions in the balancing market must be adapted to the TSO's need for adequate resources. Nevertheless, product definitions should also, to the extent possible, facilitate the participation of all relevant resources. This applies both to the definitions of activation procedures (notification, ramping time, duration, minimum bid sizes) and the reservation of reserves. For example, a wind power generator may not be able to commit to a certain level of down regulation for all hours of the year, but could provide a substantial contribution in the day-ahead (or shorter) timeframe. Hence, if TSOs contract large shares of the need for balancing resources year-ahead, it may exclude (or discriminate) resources like RES and demand response.

The cost of up and down regulation is likely to be different both for generation and load. Moreover, some sources, such as wind and solar, cannot commit to upregulation, but may provide competitive down-regulation. Therefore, the bids and prices for up and down regulation should be separated in order to reflect the true underlying marginal costs.

Remuneration

The provision of balancing resources should be remunerated according to marginal cost pricing for each hour (or each quarter, depending on the imbalance settlement period), in order to provide incentives for provision of the least-cost flexibility resources and incentivize investments in flexibility. In other words, prices for up and down regulation should be pay-as-cleared and not pay-as-bid.

In order for market participants to be incentivized to take advantage of the presumably cheaper balancing resources available in the intraday market (or in DAM), imbalance prices should also reflect the marginal cost of managing imbalances. Moreover, the imbalance settlement price should be the same for generation and load, i.e., for all BRPs.

Procurement

It is important that TSO practices when it comes to the procurement of balancing resources do not interfere with the price formation and efficiency of day-ahead and intraday markets. The market participants should be able to make the arbitrages between the market timeframes as they see fit. At the same time, the TSO may have a legitimate need to secure balancing resources for secure real-time operation. (Noting also that the TSOs need resources for within the hour balancing and not just to handle hourly deviations from the updated generation and consumption schedules.)

There are several ways in which the TSOs can procure different balancing resources. In principle, balancing reserves could be procured after gate closure in the intraday market in order to provide as much flexibility to the DAM and intraday markets as possible. However, setting such a restriction does not mean that balancing prices will not affect DAM and/or intraday prices, as the providers of flexible resources and BRPs will base their supply and demand in the intraday market on the expected value of flexibility in the balancing market. Hence, if the flexibility providers expect prices to be high in the balancing markets, they will offer less volumes to the intraday market.

If TSOs reserve capacity too early, or reserve too much capacity, distortions may occur, for example if the TSOs *reserve* too much capacity for the balancing markets prior to the DAM and intraday, and in particular on long-term contracts. The need for balancing reserves is likely to vary across time, and hence long-term procurement would mean that too large volumes are secured for most of the time, resources which may otherwise be utilized in the DAM or in IDM. As long-term contracts typically oblige market participants to bid a certain volume in a balancing product in all or certain hours (e.g., peak load) during a longer time period, these resources will not be available for intraday trade. Hence, long-term reservation should be held at a minimum, or it should be possible to offer flexibility even from reserved resources in intraday markets as "over-supply" of balancing reserves could lead to low activation prices in the balancing markets and high prices in the intraday market. (It should be noted that the bids for reservation of balancing resources are likely to also reflect the expected foregone revenue opportunities in the intraday market.)

Sharing of balancing resources across regions

Although balancing reserves to some extent have to be location specific, depending on the configuration of supply and demand (e.g. the overall market balance and the share of renewable generation), in combination with grid capacities (bottlenecks), it is always possible to use balancing resources across control zones, e.g. for down-regulation in surplus areas. Moreover, as balancing resources are not necessarily needed at the same time (and in the same direction) in adjacent zones, they may be better utilized if shared across zones. Hence, the TSOs may procure smaller volumes of reserves, and the providers of relatively cheap flexibility resources may supply a larger volume.

Regional procurement may be accomplished via bilateral cooperation between TSO, or across larger regions, involving several TSOs. Furthermore, it should be possible to reallocate IC capacity to the balancing markets, in order to efficiently utilize all transmission capacity that is not occupied by the final wholesale (DAM and IDM) market dispatch.

A first step to increased regional cooperation could be that TSOs procure balancing resources separately, according to individual needs, and then exchange resources during real-time operation. A next step could be to coordinate the procurement planning in integrated regions, and allocate the procurement among the relevant TSOs. Here, the TSOs must agree to what extent some of the resources may contribute in several control areas and thereby reducing the total amount of different balancing products. A third step could be to leave procurement to Regional Security Coordinators. However, even in this case, the procurement is likely to have to take locational issues into account.

Increased market integration implies that measures implemented nationally have spill-over effects in adjacent markets. This applies in particular to security of supply and long-term adequacy issues, but increased regional coordination could also increase the efficiency of the daily operation of the system.

In order to take advantage of the economies of coordination, the establishment of Regional Security Coordinators and Regional Operation Centres (ROCs) has been considered. These ROCs would be equipped with a minimum set of functions including the coordination of

- Short and long term adequacy planning
- Activation of costly remedial actions
- Emergency and restoration responsibility
- Training and certification
- Reserve sizing and balancing

Efficient rules for such coordination should cater for increased efficiency both in the short and long term, including more robust and less costly security of supply measures.

Participation

As in the other timeframes, cost-efficient procurement of balancing resources requires that barriers to participation are removed, and that the markets or procurement mechanisms are open to all relevant providers. Barriers to participation may stem from technical requirements, product definitions (e.g. duration, frequency or notification time), participation fees, or minimum bid requirements and lacking provisions for aggregation of bids. However, it should be observed that transaction costs are also real costs, and if products are tailor-made to a large degree, competition issues may arise. Aggregation of bids from small providers may increase the supply and reduce transaction costs, catering for broader provision of flexibility if it is profitable.

Curtailment

Sometimes, in order to avoid interruptions in supply and blackouts, the TSO may need to curtail some generation (e.g. uncontrollable RES) or disconnect some load. However, in the spirit of leaving as much as possible of the balancing to market forces and provide market-based prices for the services that are provided, such administrative curtailment/disconnection should only be executed in emergencies and after the exhaustion of all market resources. Any actions taken by TSOs that unnecessarily “overrule” market dynamics will distort short-term prices, the revenues made by different providers of flexibility, and hence, the long-term investment incentives.

Balance responsibility

As mentioned above, exemptions from balance responsibility constitute discrimination between market participants and weaken the incentives for efficient market behaviour. In order to make sure that the most efficient sources are used for balancing, all relevant resources should be balance responsible. However, in order to reap the full potential efficiency benefits of balance responsibility, the participants should also have the opportunity to react in order to reduce their balancing costs.

Hence, with the balance responsibility, the parties should also be given access to intraday markets. This means that barriers to participation should be removed. In this respect, providing the option of aggregating bids could be considered as a means to to reduce the administrative and financial costs to small actors.

2.4.2. STATE OF PLAY

2.4.2.1. Peculiarities for balancing markets

Balancing services have been important for as long as centrally operated electricity transmission systems are managed by Transmission System Operators, and significant experience has been accumulated during these years. Effectively, these services refer to the provision of necessary technical tools to the TSOs in order to secure the short-term safe operation of the system and energy supply. The combination of technical complexities and local specificities, responsibility for the security of the whole system and empirical rules which have been developed and used quite frequently, are making the TSOs traditionally quite averse to changes regarding their means of operating the system. The harmonization of the procurement rules and the products requested on a regional level can be challenging task, and need to recognize system stability and security of supply concerns on national as well as regional level.

In some markets, the procurement of balancing services takes place during the scheduling of the units, just after the gate closure for DAM. The TSOs, having market results as a starting point, develop an initial Unit Commitment program defining at the same time both the requirements for balancing services and the detailed provision (who, what, when). In that sense the potential for improvement of the operation of the system may be restricted, as discussed above.

Some of the rather technical mechanisms and interventions from TSOs, may have a significant impact on the operation of the Electricity Markets, distorting market signals and price formation. It is however complicated to analyse the impact of balancing services to market operation because their procurement is taking place exactly on the seam where market results meet the technical constraints of the Transmission System and the generating units. Nevertheless, dispatching orders from TSOs should respect the market results and willingness of market participants to deliver or absorb energy and, at the same time, secure the safe operation of the system and the technical abilities of the infrastructure to deliver the required energy.

Hence, the TSOs have the responsibility to seek services in order to solve all these technical constraints of the System, with a minimum impact on the energy market results, and to procure these services from market based mechanisms. The TSOs’ practices, that is defining the type and the volumes of balancing products required, the eligibility for the provision of these services and the timing for their procurement, are actually specifying how efficiently the energy market results can be converted to real-time dispatching orders and System operation, without distorting the market signals.

The questions to country experts and the responses gathered show the level of progress that each Member State has already made towards the targets of the Framework Guidelines on Electricity Balancing. As already mentioned, Balancing Services and Reserves have been offered for a long time, and in that sense it is well expected that all MS are following at least their own procedures for the procurement of these services, and their definition follows in almost all cases the technical standards of UCTE, securing the international operation of high voltage grids, setting the basis for defining the security and reliability standards in Europe.

According to the responses collected, the definitions for balancing services products are nearly harmonized due to the existence of the UCTE rules. Nevertheless, significant differences can be observed regarding the following more procedural elements which are used in order to summarize the proposed prioritized measures:

- Procurement methods and procedures
- Timeframes
- Eligibility and obligations from participants
- Regional Dimension, level of coordination
- Remuneration schemes

2.4.2.2. Results

Procurement methods and procedures

Most Member States have at least some market based procedures for procurement of balancing services, with the exception of Croatia, as shown in Figure 10.

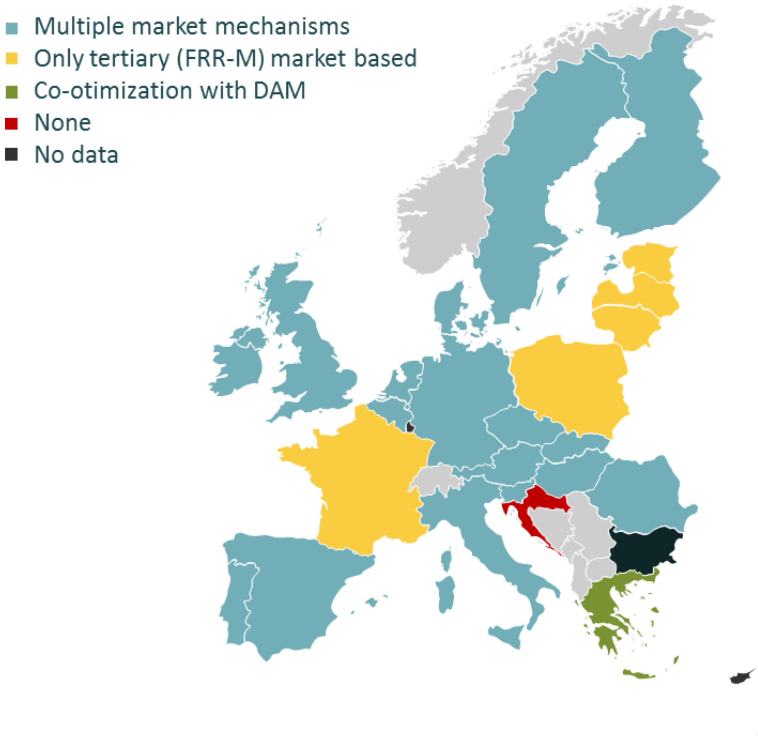
Although market based procedures exist in most Member States, their implementation varies significantly. Member States typically procure reserves on a weekly, monthly, and/or yearly basis. Furthermore, whether compensation is pay-as-bid or pay-as-cleared vary among Member States.

We have identified some Member States where there are obligations for some generators to provide balancing services, typically primary reserves (FCR). Such obligations exist in Belgium, Croatia, France, Great Britain, Italy, Portugal, Slovakia, Slovenia, and Spain. Additionally, there exist obligations to participate in the balancing markets in several Member States.

TSOs also have the ability to contract directly with specific resources, following non-market based procedures, in which case the decisions of the TSOs may affect the procurement of balancing services. According to the responses, there are a few cases were bilateral contacts between TSOs and balancing providers have been concluded, while in two cases the TSOs themselves own the resources for balancing services.

The ability of a TSO to take actions regarding the provision of balancing services, in a way that might have an impact on the DAM, is also discussed. As an example, the TSO may be able to take actions by requesting specific services from balancing providers, before the gate closure of the DAM, reducing in that way their abilities to place flexible bids in the DA market. The responses reveal that most of the TSOs are obliged to follow specific time tables for procurement of balancing reserves, and that procedures are not likely to significantly affect the operation of the DAM.

Figure 10 Overview of market-based procedures for balancing services



Price caps

Price caps apply to the activation (energy) part of balancing services in several Member States:

- In some countries there are fixed price caps, like +/-9999,99 EUR/MWh in Slovenia, +/-3700 EUR/MWh in Czech Republic, or 203 EUR/MWh for mFRR in Lithuania.

- In Austria and the Nordic countries, the floor price is equal to the DAM price, meaning that there is a guarantee that the payment for energy injected for balancing is at least on par with the DAM price.

- In Belgium, FRR prices are capped to zero (downward regulation) and to the fuel cost of CCGT plus 40 Euros (upward regulation).

Most Member States do not have price caps for capacity (reserve) bids.

Timeframes

In cases that TSOs are requesting balancing services, either from a market place or by *activating* annual, weekly, monthly or yearly tendered volumes, they should not distort the operation of other markets. The responses from the country experts indicate that in most cases actions for the provision of balancing services have no direct relation with energy markets, and do not affect price formation in these markets. Based on the collected information, it appears that all activation of balancing procurement is taking place after the closure of DAM, even if in some cases the balancing services procurement procedure is activated in the day-ahead timeframe.

Description of products

Many Member States are already using ENTSO-E's standardized definitions, while some are still using the old definitions of UCTE, which are very close to the ENTSO-E ones. A notable example where product definitions vary substantially from the ENTOS-E definitions is Great Britain, where in total 22 different balancing services are available.

All the technical definitions of some products are harmonized, while other product specifications vary greatly across Member States. Some important aspects include:

- *Symmetry requirements on bids:* Most Member States have symmetry requirements on bids for primary reserves (FCR), i.e., requiring that each reserve bid must provide both an upwards and a downwards balancing capacity. Exceptions are Western Denmark and some products in Belgium. Some Member States have symmetry requirements on aFRR, whereas no Member State have symmetry requirements in mFRR.

- *Granularity of reserve (capacity) bids:* The number of hours each bid is valid for varies among Member States. If each bid is valid for many hours (or even weeks or months), a provider is obliged to maintain generation at a level that permits ramping up or down (according to commitments), over several hours, which may cause higher costs than only providing reserves in a smaller selection of those hours.
  - FCR: Many Member States have granularity of a year, or a month. Yet other Member States have hourly resolution or multiple load blocks per day, including Denmark, Finland, Greece, Hungary, Poland, Romania, Sweden, and Slovakia.
  - aFRR: Most Member States have at hourly resolution or multiple load blocks per day. However, Belgium, Bulgaria, Denmark has a monthly granularity, whereas the Netherlands and Slovenia has a yearly granularity.
  - mFRR: The granularity for mFRR varies greatly, from yearly to hourly bids for capacity.

- *Minimum bid size:* The minimum bid size also varies substantially between Member States, between 0.3 MW to 10 MW (e.g. mFRR in Denmark, Latvia, and Sweden). A high minimum bid size may be a barrier for smaller players to participate in the markets.

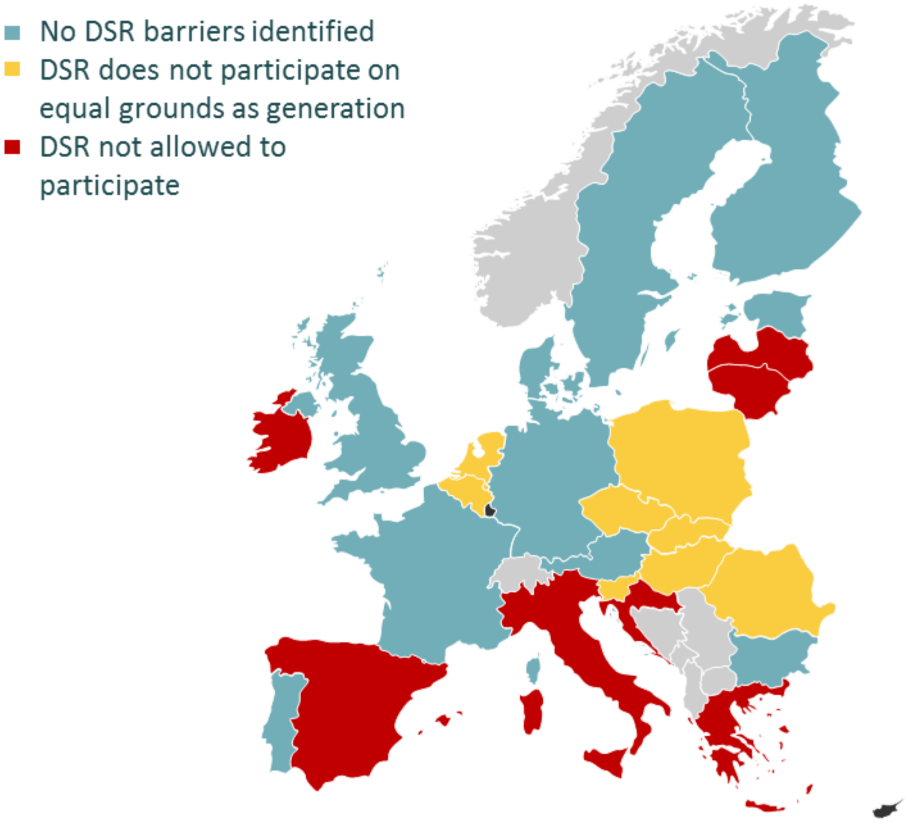
Eligibility criteria

TSOs are setting specific technical characteristics for balancing providers. In most of the cases the technical requirements are described in the tendering rules, while in other cases they are defined in the Grid Code.

In several Member States, RES and/or DSR are not able to participate in the balancing markets. The country experts have only identified explicit exclusion of RES in Italy. However, in several Member States, RES is not balance responsible, and hence not able to provide balancing services.

We have identified several Member States, where DSR is not allowed to participate in the balancing markets. Furthermore, in a number of Member States, DSR does not participate on equal grounds as generation. DSR may either be refused access to some of the balancing services (e.g. aFRR in Belgium), or DSR may be treated differently from generation in the market rules.

Figure 11 Overview of barriers to DSR participation in balancing markets



A more specific issue refers to the detailed requirements for ramping rates, where units are required to provide flexibility services, a significant issue for systems with increased RES penetration. According to the responses, in some countries the TSOs are setting specific requirements related to the ability and flexibility of the generating units to remain technically available to offer capacity in a specific time frame.

In most cases, and according to local Grid Code Rules or Trading Rules, there are no exclusions from participating as a Balance Responsible party. Nevertheless, setting specific technical criteria imposes barriers in the provision of balancing services.

Regional dimensioning and exchange of reserves

In general, the responses revealed that balancing services are mainly dimensioned and procured on a national level. However, the dimensioning of primary reserves (FCR) is in some cases regional to some extent, that is:

- A minimum requirement of 3000 MW of primary reserves in the Continental European synchronous grid is required by ENTSO-E, and each country must provide a share corresponding to its size.
- A minimum requirement of 600 MW of FCR normal operation reserve, and 1200 MW of FCR disturbance reserve is required in the Nordic synchronous grid.
- There are no primary reserves in the Baltic region, as primary control is conducted by Russia.

Dimensioning of secondary and tertiary reserves (FRR) is based on national assessments. We did not identify any MS conducting a regional assessment of reserve requirements for FRR.

It was however found that several countries have already developed mechanisms for exchange of balancing services, and they have already accumulated experience on coordinating these exchanges. Some notable regional collaborations on *exchange* of reserves are:

- Common FCR market in Austria, Germany, and the Netherlands (and Switzerland).
- mFRR exchange of reserves in France, Spain, and Portugal (each TSO with its own procurement mechanism, no common optimization)
- mFRR exchange of reserves (activation only) in Sweden, Denmark, and Finland (and Norway)
- GCC (Grid Control Cooperation) between the 4M coupled markets; the objective is netting the simultaneous and opposite differences of the control areas by means of a central optimisation process in order to avoid using secondary reserves.

Regarding the engagement of cross border capacities in balancing markets, hardly any specific approaches are employed to allocate interconnector capacity for balancing services. Nevertheless, there is significant activity in relation to bilateral exchange of balancing services through cross border interconnectors. Some MS have already set specific rules for the trading of cross border balancing services, but these are not fully implemented yet. In some cases, TSOs are performing imbalance netting, but this is not directly considered as exchange of balancing services.

Curtailment rules and practices

In general, (involuntary) curtailment *rules* are not transparent, neither when it comes to under what circumstances TSOs conduct curtailment, nor when it comes to the curtailment order (which plants are curtailed first).

Curtailment *practices* are even more challenging to describe, as curtailment occurs very seldom (or never) in many Member States. Ideally, involuntary curtailment should only be carried out as a measure of last resort.

We have identified that RES is given priority in curtailment situations in the following Member States:

- Austria
- Belgium: The TSO is responsible for the minimisation of the curtailment of RES
- Denmark
- Germany: RES and CHP, although a voluntary contractual agreement may limit priority for RES
- Luxembourg
- Hungary: RES curtailment only in case of emergency
- Poland: Although not priority in practice
- Spain: RES curtailed after conventional generation

In Ireland, on the other hand, RES curtailment is quite common.

An additional question is how the order of curtailed plants within the same category (e.g., wind) is chosen. We have not identified any explicit rules regarding how one plant is chosen above another.

2.4.3. Main Distortions

The balancing market consists of many different products, and it is not as easy to provide a simplified overview of the main features as for the day-ahead or intraday markets. Nevertheless, the below table attempts to provide an overview of the identified distortions related to balancing markets, and TSOs practices.

Table 3 Identification of main distortions in the Balancing markets

Market design feature	Comment	Main distortion?
Market Design		
Price caps	Generally, the same caps as in DAM apply, but with some exceptions.	No
Gate closure	Gate closure of energy (activation) reserves are typically close to real-time	No
Bidding requirements	Some reserve products have a time granularity of a week, month or even year. Additionally, some balancing products have high minimum bidding size (10 MW).	Possibly
Participation barriers	Technical requirements may constitute barriers to participation. Additionally, RES and DSR are not always allowed to participate in the balancing markets.	Yes
Obligations	In some MS, some or all thermal units are obliged to offer services, while RES resources are not obligated. In some MS there are similar obligations via technical (access) requirements.	Yes
Balance responsibility	Not all market participants are balance responsible, which may exclude them from providing balancing services.	Yes
Procurement		
Volume/sizing	Defined by TSOs. Some cases of direct contracting or direct TSOs ownership to balancing resources.	Probably
Timing	Specific time tables usually apply. Mostly tendering on annual, monthly or weekly basis. Sometimes just after DAM gate closure.	Possibly
Remuneration	Sometimes obligation without compensation, or with limited or regulated compensation. Remuneration may be pay-as-bid.	Possibly

Regional cooperation and coordination		
Exchange and interconnector allocation	Several MS have developed mechanisms for some bilateral exchange of balancing services, but probably far from fully exploited. Some cases of imbalance netting. No specific approaches for allocation of IC capacity for balancing services.	Probably
Coordination of balancing needs	Weak coordination. Some MS use the same tender platform for similar products. Some experience with regional evaluation of need.	Yes
Curtailment		
Curtailment rules	Some MS have a specific order/priority of curtailment.	Probably

2.5. Capacity Mechanisms

Capacity mechanisms have been or are being implemented in a number of MS. Regardless the precise mechanism chosen, they do influence the investments in generation capacity (as they have been conceived to do so). By the implementation of capacity mechanisms, not only output in terms of energy is remunerated, but also the availability of capacity is rewarded. However, if not well-designed, they carry the risk of distorting the market further by interfering in unwanted or unforeseen ways with the energy market segments, and by creating unexpected and undesired cross-border effects between different countries.

2.5.1. Crucial Market Design Features

Capacity mechanisms in various forms are implemented in order to strengthen capacity adequacy. Individual capacity mechanisms, often designed very differently, may however change the initially intended outcome of the Internal Energy Market, shifting trade and locational investment signals. Currently, the implementation of capacity mechanisms is regulated according to State Aid guidelines, and the Commission considers new and stricter regulations in order to reduce the potential distortive effects of individual capacity mechanisms.

The implementation and design of capacity mechanisms are based on capacity adequacy assessments and sometimes on explicit reliability standards. On the EU level, ENTSO-E is required to make adequacy assessments every other year. These EU-wide assessments are based on assessments made by the respective TSOs. The Commission is currently assessing whether these adequacy assessments, in their current form, are suitable to predict to what extent Member States are likely to face adequacy challenges in the medium to long term.

The Commission is considering a number of measures related to capacity adequacy assessment and capacity adequacy measures. We provide some comments on these below.

Criteria for SoS standards

In some Member States, the intervention in the form of a capacity mechanism is based on an explicit security of supply target, or a capacity reliability standard. A distinction should be made between short-term quality of supply indicators in the grid, and long-term capacity adequacy, where the latter refers to the ability of the market to equate demand and supply in the long term.

A first step towards increased harmonization of capacity adequacy measures would be to implement common criteria for the SoS assessment. For example, the same indicator could be used, one candidate indicator may be the Loss of Load Expectation (LoLE). Moreover, the LoLE could be evaluated against the Value of Lost Load (VoLL) if a Member State wishes to implement a capacity mechanism. This implies that the cost of a capacity mechanism should be weighed against its benefit in terms of the *value* of the reduction in LoLE. In principle, this should cater for an efficient level of capacity regulation – at least as seen from the perspective of the individual market.

However, the SoS assessment for each Member States should not be calculated individually, but as a part of a genuine bottom-up, European approach, where trade and interconnector capacity is taken into account. Moreover, the assessment should not be based on a static capacity margin approach, but on probabilistic modelling in order to take the variations in wind and solar generation, as well as demand, into account, and in particular the correlations between them and the correlations across larger regions.

Treatment of different resources

As argued in the discussion of balancing markets, IDM and DAM, it is important for both short and long-term efficiency and adequacy that all relevant resources are incentivized by the system. This goes for capacity mechanisms as well. Capacity mechanisms should not be limited to only certain technologies, or exclusively to generation resources. Depending on the type of capacity mechanism, even renewable electricity generators should be allowed to participate, based on the same criteria as other sources (availability, penalties for non-compliance, etc.).

Calculation of IC availabilities and rules for cross-border participation

In particular, from the perspective of the internal market and cross-European efficiency, it is important that cross-border capacity to capacity adequacy is duly taken into account, and its contribution remunerated on par with domestic resources. How to tackle this issue in regulations, is however not resolved yet, i.e. the specific rules for, e.g., de-rating, obligations and penalties need to be developed.

It is however, clear that the cross-border contribution is in any case limited by the interconnector capacity, and that the treatment of interconnector capacity, particularly with respect to the long-term investment incentives, needs to be clarified. As both cross-border adequacy resources and interconnector capacity contribute to reliability, the remuneration should in principle be allocated between the relevant resources in order to preserve (or restore) the incentives provided by an efficient energy-only market.

Right to exit without prior authorization

Even the decision to exit the market should be made on efficient economic terms. If capacity is not permitted to exit when it is deemed unprofitable, its continued presence in the market may affect the merit order curve and potentially the profitability of other market resources and the investment incentives. Hence, such practices, whether the capacity is remunerated or not, constitutes a market intervention, and a distortion of price formation.

Activation rules

How a capacity mechanism affects short-term price formation, depends on the type of capacity mechanism. While some strategic reserves imply that the capacity is used as a back-up, and only activated if the market fails to equate supply and demand, a market-wide capacity mechanism alters the total capacity level and possibly even the capacity mix, and thereby the general market merit order.

In the case of strategic reserves, the rules for activation of the reserve may distort short-term pricing and long-term investment signals. The activation of market reserves will generally impact market prices. The short-term impact on prices may also affect long-term price expectations and thereby investment incentives. This is particularly the case if the activation price is not equal to the market price cap or in the vicinity of the market VoLL. (Note that we have not included reserves that are only used for grid management in this study.)

Hence, in the case of strategic reserves, activation prices should indeed be set at a level that does not mitigate investments and the activation of demand-side response.

2.5.2. *STATE OF PLAY*

A few Member States have implemented capacity mechanisms (CM), and some are planning such implementation. While the capacity mechanisms in some MS are under revision, other Member States are discussing the issue or not considering capacity mechanisms.

CMs should be carefully designed in order to work efficiently, and should in particular take contributions from cross-border trade into account. Ill-designed CMs may distort locational investment incentives between markets, between generation technologies, between decommissioning and new investments, and between generation and load, thereby also affecting trade and the profitability of interconnectors. In addition, CMs may cause general over-capacity in the market, and induce rent-seeking instead of market-based investments in the long-term.

2.5.2.1. Reliability or SoS standards

Market distortions associated with adequacy measures could be the result if different reliability standards are applied in different Member States. Hence, in order to remove distortions associated with reliability standards, a measure may be to *introduce common criteria for reliability standards.*

Reliability standards may be set in terms of Loss of Load Expectation (LoLE), Expected Energy Unserved (EEU), and the (de-rated) capacity margin.

Loss of Load Expectation (LoLE) is the expected number of hours or minutes per year where supply does not meet the demand.

Expected Energy Unserved (EEU) describes the expected quantity of energy that will not be delivered to loads in a given year. This may be converted into an equivalent number of hours/minutes where the system load is not met. The EEU indicator is also known as Expected Energy Not Served (EENS), or as Unserved Energy (USE).

Estimates of LoLE and EEU requires probabilistic modelling of market outcomes.

The de-rated capacity margin is the amount of de-rated capacity above peak-load. De-rating implies that capacity is represented according to its expected availability during peak-load. Sometimes available import capacity is also included in the assessment of the capacity margin within a control area. Demand is usually modelled as completely inelastic in this approach.

Figure 12 and Table 4 below provides an overview of reliability standards in Europe, based on the facts gathered by the country experts. Although many of the Member States do not have explicit reliability standards, most perform capacity adequacy assessments, and as the figure shows, they overwhelmingly follow the ENTSO-E methodology, implying estimates of the de-rated capacity margin. The countries with explicit LoLE or EEU reliability standards, must however, as explained above, employ probabilistic modelling.

Most countries are also reported to take imports into account in their capacity adequacy assessments. We do not have detailed information about how the import capacity is treated however.

When it comes to taking demand side response (to prices) into account, this is reported for several countries. We do not have detailed information about the extent to which DSR is taken into account, and to what extent or how price-based and incentive-based schemes are taken into account. When it comes to Sweden, the methodology does however explicitly take into account the demand response potential represented in the peak load reserve.

Figure 12 Reliability standards and measures

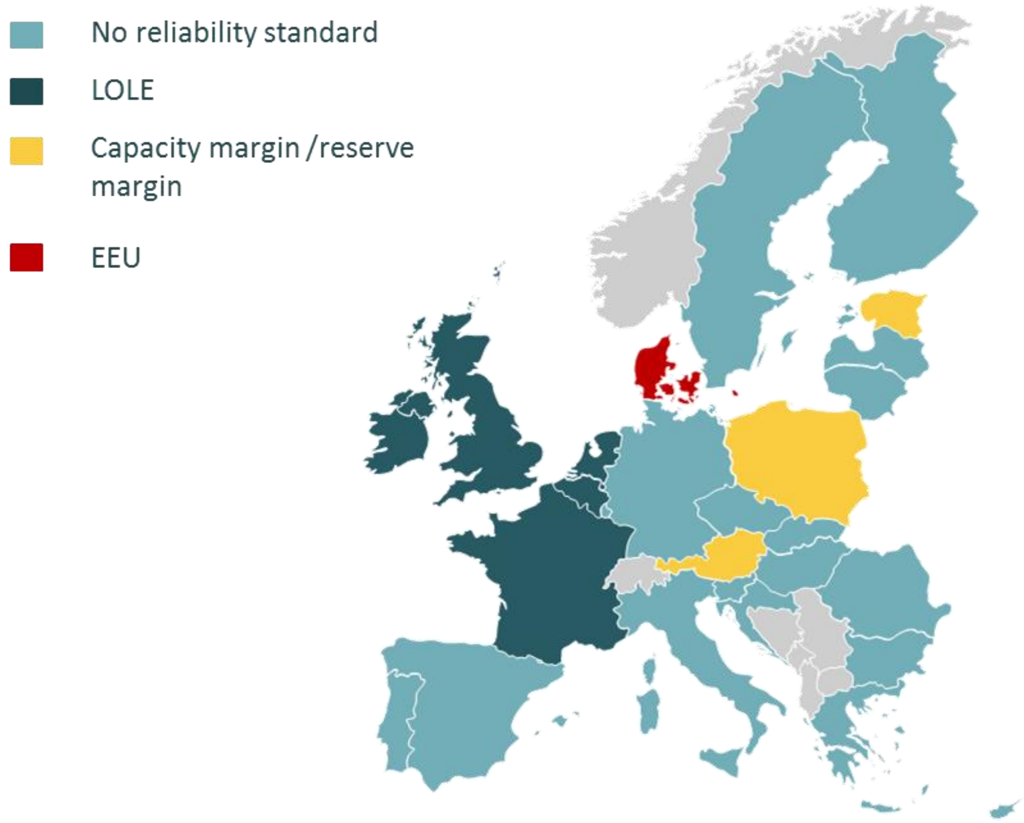


Table 4 Overview of current reliability standards in Europe

	Reliability standard	Capacity adequacy methodology	Imports/DSR included
Austria	Capacity margin	ENTSO-e guideline	No/No
Belgium	LOLE < 3 h/year	ENTSO-e guideline	Yes/Yes
Bulgaria	N/A	N/A	N/A
Croatia	N/A	ENTSO-e guideline	Yes/No
Czech Republic	No	ENTSO-e guideline	Yes/No
Denmark	EEU < 5 min/year	Probabilistic modelling	Yes/No
Estonia	Min. 10% reserve margin	N-1 criterion	Yes/N/A
Finland	No	Peak load margin	Yes/Yes
France	LOLE < 3 h/year	Probabilistic ?	Yes/Yes
Germany	No	ENTSO-e guideline	Yes/Yes
Great Britain	LOLE < 3 h/year	Probabilistic modelling	Yes/Yes
Greece	No. New standard under development	Probabilistic modelling	Yes/Yes
Hungary	No	Ad hoc. Partly ENTSO-e guideline*	No/No
Ireland	LOLE < 8 h/year	Probabilistic ?	N/A
Italy	No	ENTSO-e guideline	Yes/Yes
Latvia	No	N/A	Yes/N/A
Lithuania	No	N/A	Yes/N/A
Luxembourg	N/A	N/A	N/A
Netherlands	LOLE < 4 h/year	ENTSO-e guideline	Yes/Yes
Poland	Min. 9% reserve margin	N/A	Yes/No
Portugal	No	ENTSO-e guideline	N/A
Romania	No	Probabilistic modelling	Yes/No
Slovakia	No	ENTSO-e guideline	Yes/No
Slovenia	No	ENTSO-e guideline	N/A
Spain	No	ENTSO-e guideline	N/A
Sweden	No	Ad hoc/ENTSO-e	Yes/Partly

2.5.2.2. Capacity Remuneration Mechanisms

Categories of capacity mechanisms

Before describing the information on capacity mechanisms (CM), it is useful to define the main categories, which are

- Capacity payments
- Strategic reserves
- Capacity markets

Capacity payments

Capacity payments are usually fixed (annual) payments targeted to specific technologies. The payments may be differentiated between technologies, and the fees are usually set administratively. Capacity payments are typically only paid to generation. The only obligation is usually that the capacity is not decommissioned or mothballed, i.e. it is active in the market.

Strategic reserves

Strategic reserves may include both generation and demand side resources. We should distinguish between strategic grid reserves and generation adequacy reserves:

- Strategic grid reserves are held by the TSOs and can only be used in the operation of the grid, i.e., the reserve (usually generation capacity) is used instead of other measures available to the TSO in the real-time management of the system.

- Generation adequacy reserves are used to balance the market if demand and supply do not intersect.

Thus, generation adequacy reserves might affect market prices directly (day-ahead and balancing markets), whereas strategic grid reserves should not, although may affect re-dispatching and its remuneration. The distinction is however, not clear-cut, and in some cases the use of strategic grid reserves may, at least indirectly, impact the market depending on the rules for its use and to what extent it is left to the discretion of the TSO. The reserves may represent a distortion if these reserves are used instead of balancing reserves procured from market participants.

A different example is the current German reserve, which is used for re-dispatch to manage internal congestions. This does not directly affect DAM market prices. However, if the alternative is to implement bidding zones, then market prices are in fact indirectly affected.

Capacity markets

Capacity markets come in a vast variety of designs, from capacity auctions to reliability options. All of them may not qualify as full-fledged markets, but their procurement is generally market-based, i.e. the remuneration is set according to supply and demand.

Considered measures

The considered measures related to capacity mechanisms are:

- Treat all resources equally based on reliable availability
- Require TSOs to calculate IC availabilities and develop rules for cross-border participation
- Implement common rules for triggering of activation and pricing of activation for strategic reserves

The table below provides an overview of some of the main results. As can be seen, most of the Member States do not have capacity mechanisms. The ones who do, are distributed among the three main types as follows:

- Capacity payments: Latvia, Lithuania, Portugal, and Spain
- Strategic reserve: Belgium, Finland, and Sweden
- Capacity market: France, GB, Ireland, and Italy

Greece also has a capacity mechanism in the form of a flexibility obligation, but this is a transitional arrangement, while a new capacity mechanism is pending. Poland also has a transitional strategic reserve, and a standardized capacity payment for non-dispatched capacity. In addition, some countries have interruptible demand contracts, mainly with industries, which constitute a form of strategic reserve as well.

Figure 13 Overview of capacity mechanisms

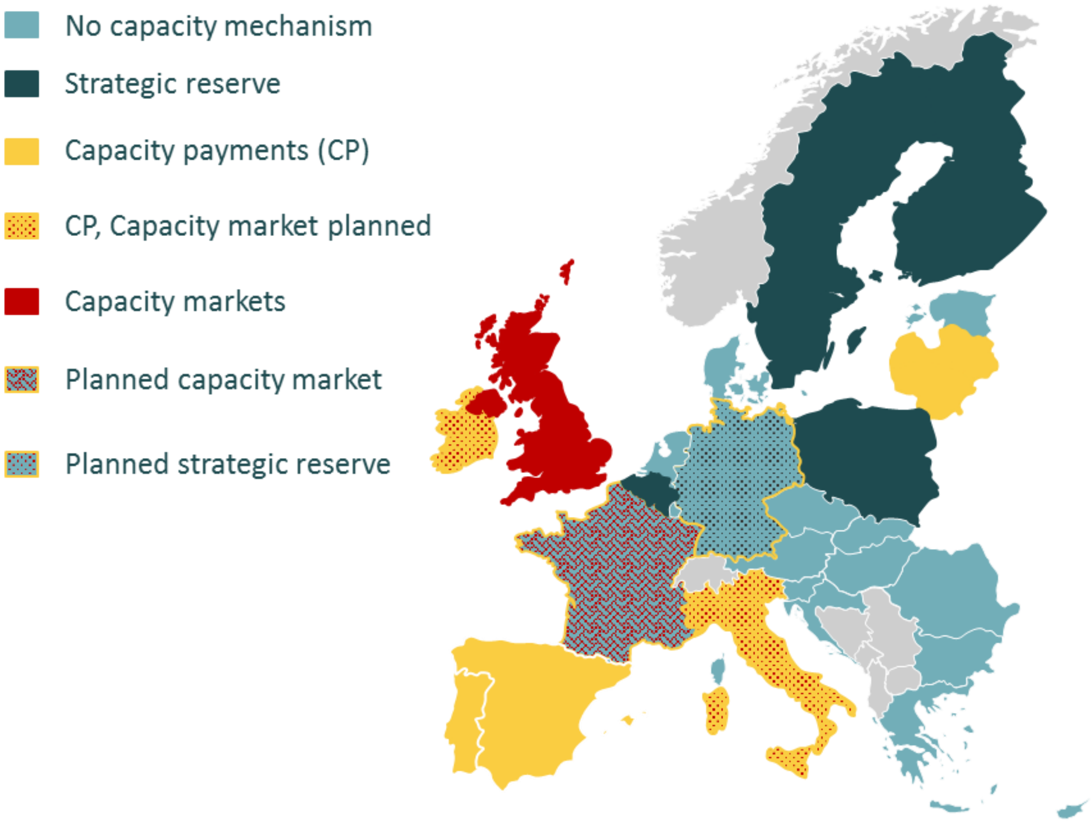


Table 5 Overview of existing Capacity Mechanisms in Europe

	Mechanism	De-rating	Participation	Remuneration	Activation
Belgium	Strategic reserve	Yes, DSR	Not RES	Pay-as-bid (reservation and activation)	Missing DAM equilibrium, pay-as bid
Finland	Strategic reserve	N/A	Open to all	Pay-as-cleared (annual auction)	No DAM equilibrium/ insufficient reserves, highest variable bid + 0,1 Euro/MWh*
France	Tender for new capacity in Brittany Decentralized Capacity Obligation planned	CO: Yes, RES and hydro	CO: Market-wide	CO: Market based (tradable certificates)	CO: No activation
Germany	Strategic grid reserve Strategic market reserve planned	N/A	N/A	N/A	N/A
Great Britain	Capacity auction	Yes	Market-wide incl. IC	Pay-as-cleared with ceiling	No activation
Greece	Transitional Flexibility Obligation Capacity mechanism planned	Yes	Limited by technical requirement	Regulated price	No activation, central dispatch
Ireland	Market-wide capacity payment Reliability options planned	CP: According to generation RO: Under discussion	RO: Market-wide	CP: Rates differentiated per hour RO: Option premium, pay-as-cleared	CP: No activation
Italy	Targeted capacity payment Reliability options (zonal) planned	RO: No (market-based)	RO: Market-wide	RO: Option premium, pay-as-cleared	RO: No activation
Latvia	Capacity payment	N/A	N/A	Fixed price	N/A
Lithuania	Capacity payment	N/A	N/A	N/A	N/A
Poland	Temporary hybrid: Strategic reserve/Targeted capacity payment	N/A	N/A	N/A	N/A
Portugal	Capacity payment	N/A	Only thermal and hydro	Annual calculation per unit	No activation
Spain	Capacity payment	Yes	Only thermal and hydro	Regulated availability payment	No activation
Sweden	Strategic reserve	N/A	Open to all	Annual auction, pay-as-cleared	No DAM equilibrium/ insufficient reserves, highest variable bid + 0,1 Euro/MWh

Sources: Information gathered from country experts, Interim Report of the Sector Inquiry on Capacity Mechanisms

Several countries have grid or emergency reserves, and it is not always clear to what extent these impact the market, or whether they can also be used if the market fails to find equilibrium. For example, Estonia, Lithuania and Latvia have emergency reserves controlled by the TSO, while the current German reserve is used exclusively to handle grid congestion.

In addition, we also asked the country experts to identify questionable practices related to the above. Not much information was provided. For Hungary, it was noted that ad hoc capacity adequacy assessments are carried out and that measures may also be taken on an ad hoc basis.

We may however, comment on one possibly questionable practice. The Finnish and Swedish peak load reserves are activated if the DAM cannot establish equilibrium, or if the TSO is unable to procure sufficient balancing reserves. Hence, the capacity is not activated until all market resources are exploited. However, when the reserve is activated, the market price is set marginally above the last variable bid in the market. This pricing rule may constitute a soft price caps, and could mitigate flexible bids in the market, particularly from the demand-side: A high DSR bid implies a higher market price whether the reserve is used or not. If the activation price was set equal to the price cap, the demand side would have a stronger incentive to provide flexible bids in order to avoid extreme prices.

In general, the capacity mechanisms, with an exception for the GB auction, do not cater for explicit cross-border participation.

2.5.2.3. Barriers to exit

As explained in chapter 2, barriers to exit may also distort short term price formation and long-term investment incentives in the market. And of course, different rules in different market also distort the efficiency of the Internal Energy Market.

Therefore, a possible measure is to ensure the right to exit without prior authorization.

Only a few countries are reported to employ barriers to decommissioning of generation capacity:

In *Belgium*, generation units need to announce decommissioning 1 year ahead. The TSO includes the announced closure in the simulation to determine the size of the Belgian Strategic Reserve. If there is a volume of SR contracted, the generating units is to make an offer to the Strategic Reserve. If it is selected for the Strategic Reserve, the decommissioning is denied. Otherwise the generating unit can be decommissioned.

Croatia expects decommissioning of older power plants in the coming years, and plan to check the need for this capacity for tertiary reserves and heat consumption.

In *Germany*, the vitality of the power plant for the system is assessed by the TSOs before decommissioning is permitted. If the plant is vital to the system, it is placed in the grid reserve and remunerated according to specific tariffs.

2.5.3. MAIN DISTORTIONS

The European map of capacity mechanisms is changing. New Member States are planning to implement and others are revising their capacity mechanisms. A total of 14 MS have implemented or are planning to implement some kind of capacity mechanism. The trend seems to be moving towards either targeted strategic reserves or market-wide capacity markets.

The main distortions related to capacity mechanisms that can be identified are:

- Inadequate reliability standards and capacity adequacy assessment methods, implying that capacity requirements may be set too high and not in compliance with VoLL.

- Capacity adequacy assessments and capacity requirements take DSR and import contributions into account, but the capacity assessments generally do not take a regional perspective.

- Cross-border participation is generally not allowed. This means that individual capacity mechanisms are likely to distort the locational investment incentives between countries, in particular if the capacity requirement is set too high, including the investment incentives for interconnectors.

- Rules for the activation of strategic reserves may mute scarcity pricing, and thus incentives to invest in flexible generation and DSR resources.

- Barriers to exit exist in some countries, and may distort the markets similar to the activation of strategic reserves.

2.6. Other Market Design Aspects

Other regulatory and market aspects may affect the efficiency of investment incentives in the markets as well. In particular, we have asked the country experts for input on the following market design aspects not pertaining directly to capacity mechanisms, or day-ahead, intraday or balancing markets:

- Hedging opportunities, as proper risk management mechanisms are important for investments

- Network tariffs for generators, as the structure and level of such tariffs may distort investment incentives among countries and technologies

- Retail price regulation, as such regulation may hamper demand-side response and thus the efficiency of price formation in the markets

We elaborate on these issues below.

2.6.1. Hedging Opportunities

2.6.1.1. Crucial Market Design Features

An important issue for investors is the availability of risk management instruments. In order to reduce the cost of capital, investors seek to distribute their risks, and in particular to reduce their exposure to spot market price volatility. Hence, the existence of hedging instruments, be it long-term bilateral contracts or financial instruments such as forwards, futures and options, may facilitate investments, in particular in capital-intensive generation capacity.

Therefore, the Commission has considered whether barriers to long-term contracting exist, and whether the development of option products should be stimulated.

Barriers for long-term contracting and availability of option products

Increasing shares of intermittent renewable generation with close to zero marginal costs, in combination with long-term market and policy uncertainties, have increased the risks in the power market over the recent years. In addition to the price risks, the volume risks for peak-load capacity have also increased.

The development of hedging opportunities could be facilitated by improved functioning of wholesale markets and more predictable price formation via efficient balancing, better utilization of interconnector capacity and the sharing of resources across larger regions. However, to the extent that there are particular implicit or explicit barriers to long-term contracting, these should be removed. Preferably, liquid financial trading in the market should be rewarded, while making sure that market prices are not distorted.

Opportunities for risk management and hedging is vital for long-term capital intensive investments. We therefore asked the country experts to report on any possible barriers to long-term contracting in the market, and to provide indicators for the liquidity of financial markets.

2.6.1.2. State of Play

The information gathered by the country experts is presented in Figure 14 and Table 6.

The question on barriers to long-term contracting was not easy to answer. In most markets, fees and collaterals related to financial trading on the exchange are listed as a barrier. However, whether these constitute distortions depends on the level of the fees. Additional information is provided in the facts template.

We asked for turnover ratios as a simple indicator for liquidity in financial markets. The turnover ratio is a measure of liquidity in financial markets and expresses the relation between the volume of financial trades compared to the day-ahead volume. This way, turnover ratios could be an indicator on the extent to which the concerned markets are well-functioning or rather less mature, without explaining the possible underlying reasons. It should be noted that they do not capture all aspects of market liquidity. Turnover were not calculated for all markets.

We see that the most liquid markets are, not surprisingly, found in the Nordic area, including the Baltic states, and in Austria, Germany, Luxembourg, and the Netherlands. At the other end of the scale, with a turnover ratio below one, we find Belgium, Greece, and Portugal.

2.6.1.3. Main Distortions

The results indicate generally relatively low liquidity in financial markets, although regulatory or market design barriers to long-term contracting do not generally seem to be the main reason for this.

Figure 14 Overview of turnover ratios for financial trade

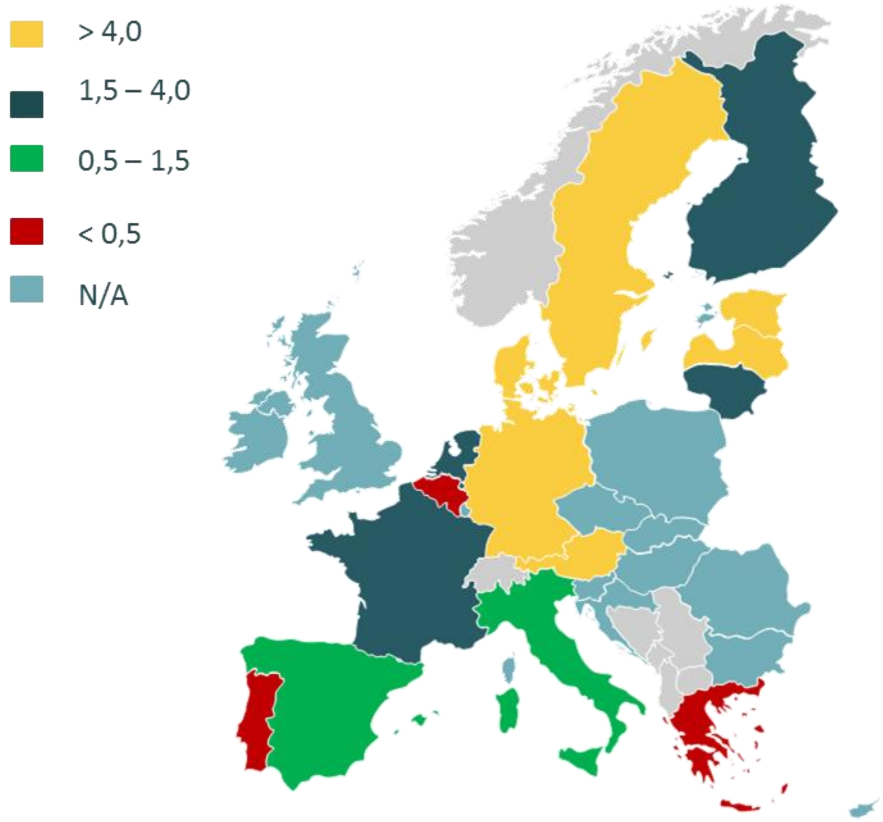


Table 6 Overview of barriers to long-term contracting and turnover ratios

	Barriers to long-term contracting	Turnover ratio
Austria	No	6,35
Belgium	No	0,23
Bulgaria	All contracts long-term	N/A
Croatia	N/A	
Czech Republic	No	
Denmark	No	4,08
Estonia	N/A	5,64
Finland	No	2,37
France	Regulated access to nuclear energy	1,98
Germany	No	6,35
Great Britain	No	
Greece	High market concentration	0,1
Hungary	No	
Ireland	No	
Italy	Low liquidity in peak contracts	1,28
Latvia	N/A	4,15
Lithuania	N/A	3,93
Luxembourg	No	6,35
Netherlands	Only simple forwards available	3,04
Poland	No	
Portugal	No	0,13
Romania	No. Nearly 75% transacted in OPCOM in long-term hedging products.	
Slovakia	No	
Slovenia	N/A	
Spain	No	1,05
Sweden	No	4,28

2.6.2. NETWORK TARIFFS FOR GENERATORS

2.6.2.1. Crucial Design Features

Network tariffs should generally contain variable charges, such as losses and customer-specific costs, and fixed (preferably lump-sum) charges allocating residual costs among grid customers in a neutral manner. I.e., the residual elements should not yield short-term price signals.

There are different practices when it comes to the application of residual tariff elements (so-called G-tariffs) in the Member States. If G-tariffs differ, it may affect both short-term operation and long-term investment signals.

As an alternative to price areas, the Commission is considering whether G-tariffs be differentiated according to location, in order to mitigate the lack of locational signals in the DAM prices. Moreover, grid tariffs should not discriminate between generation connected at different grid levels. Thus, for G-tariffs we focused on two possible measures:

- Implementation of a locational signal in the G-tariff
- Alignment of the G-tariffs in the transmission and distribution grids

We comment on these possible measures below.

Locational signal components in transmission tariffs

Some Member States are strongly opposed to implementation of domestic bidding zones. As explained above, maintaining one single bidding zone in a situation with imbalances and frequent internal bottlenecks, reduces the efficiency of locational investment signals. This threatens to exacerbate loop flow problems spilling over to adjacent markets.

An alternative measure to introduce locational investment signals, is via the transmission grid tariff. In particular, one option that is considered is to introduce locational signals in the so-called G-tariff, or the G-component in the generator tariff. The G-component is the part of generators' grid tariff that is generally *not* intended to yield price signals to grid customers (the residual tariff).

Although it may be desirable to, in the absence of bidding zones, to introduce locational *investment* signals via grid tariffs, one should be careful that the tariff does not distort the short term operation of generators.

If different G-components are applied in different markets, locational signals may be distorted nevertheless. For example, ACER holds the opinion that "there is an increasing risk that different levels of G-charges distort competition and investment decisions in the internal market".[19] In order to limit this risk, G-charges should be "cost-reflective, applied appropriately and efficiently and, to the extent possible, in a harmonised way across Europe." In order to work as intended, the tariffs must be set according to the same principles across Member States.

It is however important that G-tariffs are lump-sum. For example, energy-based tariffs based on historical generation will not affect the short-term incentives to generate, whereas per MWh tariffs increase the marginal cost of generation and thereby the merit order curve.

G-tariffs in the distribution and transmission grids

As mentioned above, grid tariffs should in general not discriminate between grid customers, apart from cost elements that may clearly be associated with the connection or consumption of that particular customers. On implication of this, is that due to differences in losses and connection costs, generation connected at the distribution level and at the transmission level should pay grid charges according to the same principles, and be subject to the same G-elements.

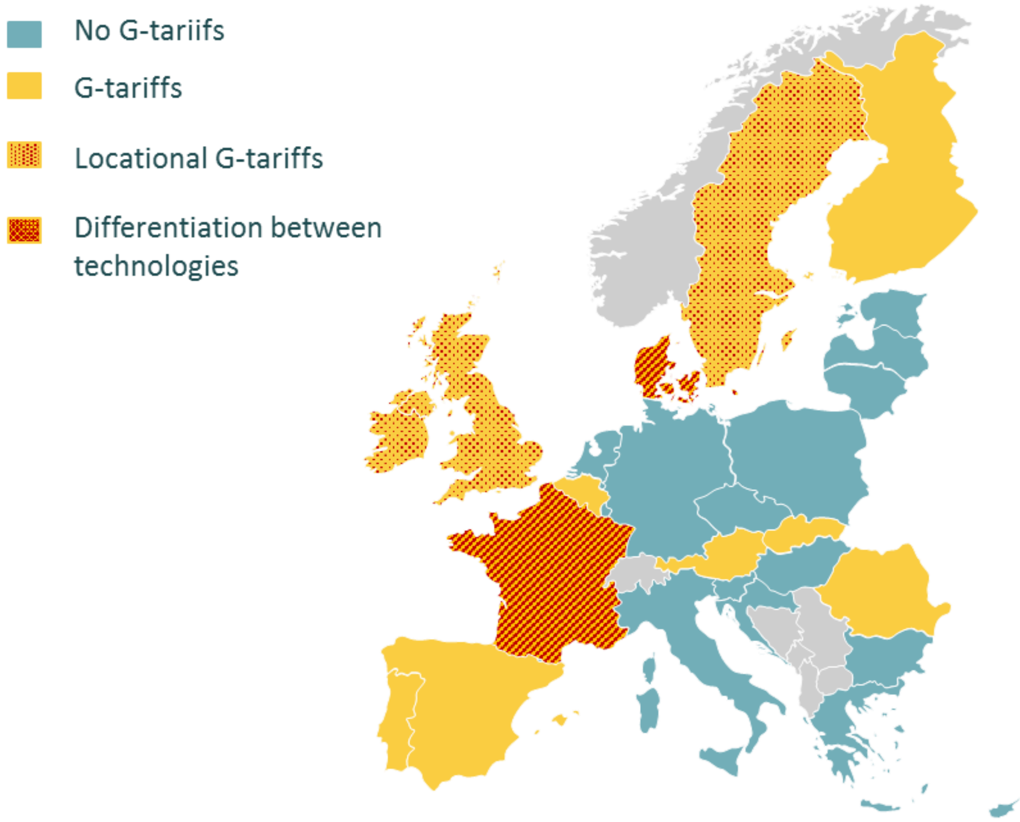
[19] Opinion of the Agency for the Cooperation of Energy Regulators No 09/2014 of 15 April 2014 on the appropriate range of transmission charges paid by electricity producers.

2.6.2.2. State of Play

The responses from country experts reveal that most Member States do not impose G-elements in their tariffs, and the ones who do, generally do not differentiate according to grid location.

Of all the Member States, 12 apply grid tariffs to generation at all, namely Austria, Belgium, Denmark, Finland, France, Great Britain, Ireland, Portugal, Romania, Slovakia, Spain and Sweden. Among those who do, only Great Britain, Ireland and Sweden apply locational differentiation, while Denmark discriminates between technologies. In France, there are several "special tariffs" differentiated according to different criteria, although these seem to mainly apply to demand-side grid customers.

Figure 15 Overview of G-tariffs



It is clear from the information that locational signals in the grid tariff are general not applied, and that implementing such a measure would require a substantial change in the current distribution of grid costs between generation and load.

We also note that the three countries which do apply locational signals, all seem to relate it to differences in future transmission costs. It is also interesting to note that Sweden applies a locational tariff in addition to price area delimitation. The Swedish locational tariff does however also vary within price areas (according to latitude).

Moreover, the Swedish tariff is based on subscribed capacity. This structure may reduce the profitability of investing in peak load capacity, as the increase in the G-tariff may be high relative to the risk of only using the capacity when prices peak (Thema, 2015)[20].

Table 7 Locational price signals in network tariffs, overview of European practices

	Locational signal?	Basis for the locational element?	Discrimination between technologies?
Denmark	No	N/A	Wind turbines and local CHP units subject to purchase obligation are exempt
France	No		Network development costs due to RES integration are mutualized on a regional basis. For other technologies connection charges are based on actual costs.
Great Britain	Yes, Transmission Use of System Charges, covering costs for installing and maintaining the grid.	Surplus and deficit areas.	No. Applies to load as well.
Ireland	Yes. Generation Network Location-Based Capacity Charge in Euro/MW/month according to maximum export capacity.	The charge is calculated "considering the usage of current generation on future network using a "reverse MW mile" methodology.	No.
Sweden	Yes. Based on subscribed capacity.	Latitude.	No.

<u>Differentiation in G-tariffs between the transmission and distribution level</u>

Generally, we have not found much information about G-tariffs in the distribution grid. For some countries there appears to be such differentiation, though:

- France: The G-charge covers costs for inter-TSO compensation mechanisms and consequently only generation on high voltage level is charged.
- Portugal and Spain: For Portugal it is reported that the tariffs follow the Spanish model and are differentiated according to grid level, although for Spain no such differentiation is mentioned.

2.6.2.3. Main Distortions

Investment incentives for generation is likely to be somewhat distorted given the current diversity in G-tariffs.

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20 http://www.thema.no/wp-content/uploads/2015/04/THEMA-Report-2014-43-FINAL-Harmonisation-of-transmission-tariffs.pdf

2.6.3. *Retail Market Price Regulation*

2.6.3.1. Crucial Design Features

The demand side can play a much more active role in the market than what is currently the case in most Member States. The demand side may react to prices indirectly or directly:

- Indirectly, by adjusting consumption to price signals
- Directly, by placing bids in the flexibility markets or reacting to incentive schemes

Both responses are important for price formation and long-term adequacy. However, as long as large parts of the demand side are subject to regulated prices, not reflecting movements in short-term market prices, the consumers do not have any incentives to react to prices or provide flexibility in any of the market time-frames. It should be noted however, that even if prices are regulated, consumers can respond via various incentive schemes. The separate study on downstream flexibility (see footnote 2) discusses various incentive-based measures in more detail.

One particular proposal in order to engage the demand side in the market, is in any case to phase out retail price regulation, thereby exposing end-users to market price levels and variations.

Price regulation

As long as end-users cannot be billed according to their actual hourly (or half-hourly) consumption, the incentives to adapt to price signals is weak, both in terms of short-term adaptation and changes in equipment and/or behaviour for long-term adaptation. In particular, if end-user prices are subsidized by regulation, consumption patterns will be distorted, both over time and towards alternative energy carriers.

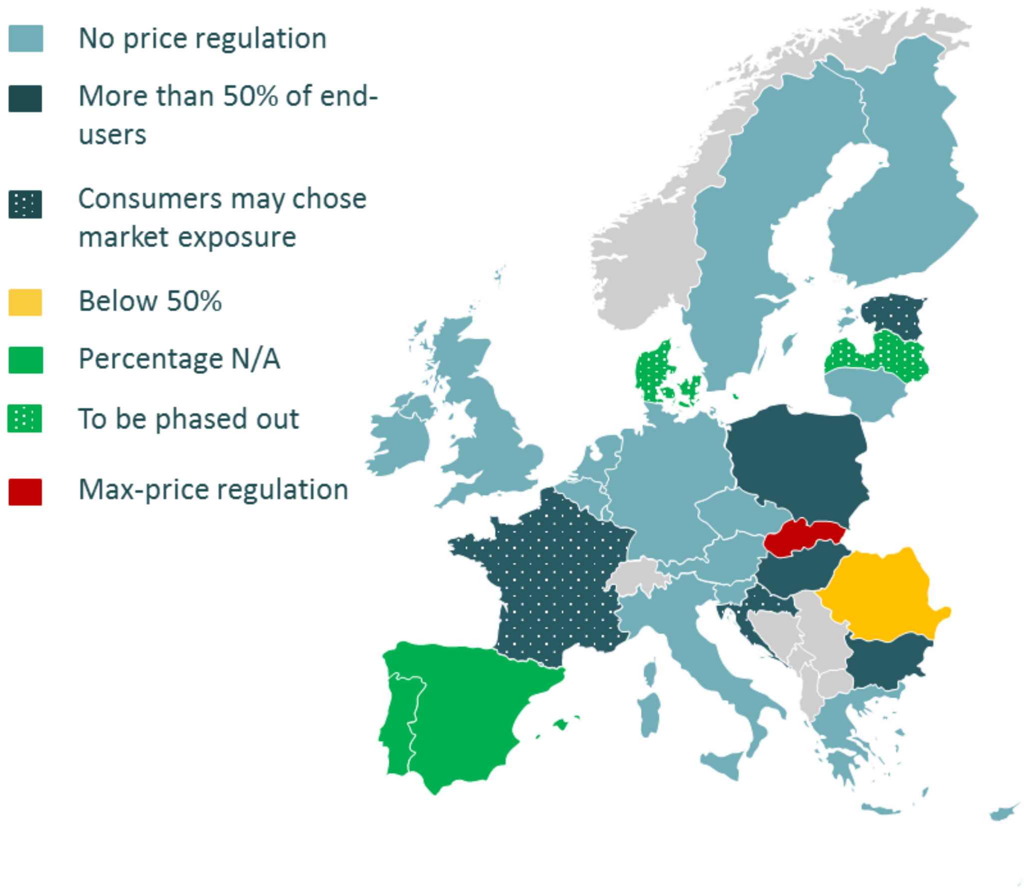
With the roll-out of smart meters, it is possible to expose end-users to hourly price signals and install control systems for automatic adaptation. Hence, in order to take advantage of these opportunities in an efficient manner, it is likely to be an important measure to phase out retail price regulation.

2.6.3.2. State of Play

The responses from the country experts show that 12 countries, namely Austria, Belgium, Czech Republic, Finland, Germany, GB, Greece, Ireland, Italy, Netherlands, Slovenia, and Sweden, are reported to not have regulated retail prices.[21]

[21] In the Netherlands, all energy prices must be submitted to the regulator, who may force suppliers to lower their prices if they are deemed unreasonable. The regulator has so far not exercised this right.

Figure 16 Overview of retail price regulation



The following countries do however maintain a significant share of end-users on regulated contracts:

Country	Share in %	Comments
Bulgaria	55	
Croatia	80	Consumers may choose exposure to market prices
Denmark	n.a.	To be phased out
Estonia	17	
France	92 / 86	Residential / Industrial (2013). Consumers may opt for market prices
Hungary	70	
Latvia	n.a.	To be phased out
Poland	90	2015
Portugal	n.a.	To be phased out
Romania	34	
Slovakia		Maximum price regulation
Spain	n.a.	To be phased out

However, quite a few countries report that regulated prices should have been phased out during 2015, or that a road map for their removal exists, including Denmark, Latvia, Portugal and Spain.

2.6.3.3. Main Distortions

Quite a few countries are found to apply price regulations which may mute demand response, particularly in peak price hours. The extent of this distortion in terms of price effects depends partly on the costs associated with price response. With the roll-out of smart meters and new communication technologies, these costs should be reduced.

It should however, be noted that DSR among small consumers may be more effectively activated via incentive-based schemes and aggregator services.

2.7. Summary of Main Distortions

Related to distortions in the day-ahead market, the intraday market, and the balancing market, we have identified the following main distortins:

- Non-harmonized price caps. Maximum price caps set lower than VoLL, likely to affect scarcity pricing. Minimum price levels too high, implying increase use of involuntary curtailment.
- RES support schemes varying significantly between MS, and directly or indirectly distorting the merit order.
- Absence of a level playing field for all generation resources in all market time-frames, due to must-run generation, priority dispatch, lacking access to markets, and exemptions from balance responsibility
- Inefficient bidding zone delimitation
- Lack of intraday market coupling and non-harmonized technical specifications of intraday and balancing markets
- Interconnector capacity not optimally allocated across time-frames
- Sizing of balancing reserves based on national, deterministic approaches
- Barriers to the participation of demand side resources in all market time-frames, and for RES in intraday and balancing markets
- Obligations to provide balancing services without proper remuneration

In addition, evidence suggest that the following features probably constitute significant barriers:

- Barriers to DR participation
- Curtailment of interconnectors to handle internal congestions
- Lack of regional coordination of ATC calculation
- Significant variation in intraday price caps
- Procurement of balancing services on long-term horizons
- National activation of balancing reserves and lack of cross-border exchange of balancing resources

- Inefficient practices for involuntary curtailment
- Cross-border exchange of balancing resources not fully exploited

3. BASELINE MODELLING – THE DISTORTED SCENARIO

The main purpose of the impact assessment is to estimate the losses associated with distortions related to imperfect market design, including TSO practices. The benchmark in this case is a perfect market (in theoretical terms), including full access of information. The modelling of the theoretically perfect market is relatively straightforward, and is the usual approach to market modelling. However, in order to estimate the losses associated with distortions, we need to model how the identified distortions affect the market outcome.

This chapter deals with the major market distortions and how such distortions can be modelled in a baseline scenario. The chapter includes a discussion about data and availability of data that can be used in modelling the distortions. The distorted scenario, or baseline scenario can then be used to estimate the value if distortions are lifted by implementing different policy measures, hence moving closer to the "perfect" solution.

The distortions are grouped by the different policy measures that are meant to address them. For each measure, we describe the distortions that are addressed, discuss how the distortion could be simulated in a model framework, and what type of data would be required to model it. For those distortions where relevant data is missing, we propose alternative proxies that could be used to implement the distortions. Our modelling suggestions are relatively generic, and apply mostly to fundamental power market and simulation models, i.e. models that minimize (dispatch) costs under a set of constraints (hence implicitly assuming perfectly competitive markets). But even fundamental models can be different in nature and focus points, and naturally the implementation of distortions depends on the specific model framework.

Note that some of the distortions and measures are related. For example, the role of balance responsibility also plays a role for sizing of balancing reserves. Thus there may be some natural overlap in the subsequent sections.

3.1. LEVEL PLAYING FIELD FOR ALL GENERATION

3.1.1. DISTORTIONS TO BE ADDRESSED

Measures to create a level playing field for all generation concerns day-ahead markets, intraday markets, and balancing markets. The measures essentially address three different types of distortions:

- Must-run generation and priority dispatch: Some types of generation (e.g. RES, CHP, Biomass) may have priority dispatch. This distorts the market outcome as these types of generation do not enter the merit order according to their actual marginal cost structure.

- Market access: Some resources may not be allowed to participate in certain markets (e.g. balancing markets) and are a-priori excluded from these markets. This results in a suboptimal portfolio of assets that could contribute in these market.

- Balance responsibility: Some generation may not be balance responsible. This can affect both the supply of flexibility (in intraday and balancing markets) as well as the sizing of reserves that TSOs have to procure.

In an ideal market, all generation would be treated equally in all time-frames. Whether certain types of generation would be active in certain markets would then be a result of the marginal cost structure.

3.1.2. How to model the distortions

Must-run generation or priority dispatch is fairly straightforward to model. Must-run generation can be implemented in a model by fixing the output (as opposed to being optimized by the model). Alternatively, one can model different types of generation with negative generation costs which could reflect market premiums or other support mechanisms.

Restricted market access is also easy to address in a model by excluding certain types of generation from the optimization problem. This increases the procurement costs in the affected markets.

More of a challenge is to model correctly the effect that parties are not balance responsible. Excluding certain types of generation from the intraday market in case they are not balance responsible reduces the liquidity in that market as both demand and supply for flexibility are reduced. Note in this respect that even RES generation can provide downward flexibility.

At the same time, RES generation may increase the overall balancing requirements that need to be purchased by the TSOs in balancing markets. In addition, making generation balance responsible may also improve incentives to provide more accurate forecasts, hence decreasing the amount of flexibility needed to handle imbalances. Thus one way of addressing this type of distortion indirectly in the modelling is to adjust the balancing volumes procured by TSOs.

A special challenge is the modelling of CHP plants that produce both power and heat. There are different types of CHP plants, some of which have a fixed ratio between power and heat generation (i.e. the power generation is determined by the amount of heat produced; these are typically price takes in the power markets), and some of which are more flexible (i.e. heat generation defines a lower and upper bound for power generation). In addition, the heat generation profile may differ substantially between CHP plants, depending on whether they produce heat for industrial purposes (rather flat heat generation), or for public district heating networks (rather seasonal heat generation).

There are two approaches to model CHP in a power market model:

1. Some power market models simulate the heat markets simultaneously (integrated power and heat models). In this case, power generation is co-optimized together with heat supply.

2. Most power market models do not model the heat markets explicitly. In this case, heat obligations can be captured by adding fixed power generation profiles (in case of inflexible CHP plants) or minimum and maximum generation profiles. In both cases, one can use technical data for CHP plants and heat generation profiles to estimate these profiles.

3.1.3. Data considerations and challenges

In our data sets we outlined detailed information about priority dispatch, such as whether types of generation are excluded from certain markets and what types of generation are balance responsible. This information can be directly translated into constraints in the model or by defining which types of generation are allowed to provide flexibility. Generation profiles (heat and power) for CHP plants are available at least for some countries. For countries where such data is missing, temperature data may be applied to estimate heat demand profiles.

The challenging part, however, is to find a good proxy for what priority dispatch implies for the sizing of balancing reserves. In general, the imbalance that occurs between the day-ahead market (which is essentially a short-term forward market) and the actual moment of delivery has to be handled. This imbalance can be handled by TSOs via balancing markets, and/or by market participants in intraday markets, or outside the markets within the portfolio of a BRP, or by bilateral agreements. One can roughly decompose the issue into the following parts:

- day-ahead market balance – physical balance during moment of delivery: This is the difference between the day-ahead schedule and what happens in the actual hour of operation. Making parties balance responsible implies that the forecasted day-ahead balance may become more accurate. The resulting difference hence decreases, and so does the TSOs need for balancing reserves.

- The remaining difference between the DAM solution and the real-time solution can be split up into a delta that is handled in IDM, and a delta that is handled by TSOs in balancing markets. The larger the delta handled in IDM, the lower the delta that needs to be handled by TSOs.

No single variable could indicate how the sizing of balancing reserves changes with balance responsibilities and increased participation in say IDM. However, what is known is the forecasting error for RES generation depending on the forecasting horizon. Better incentives for forecasting and active participation in IDM is likely to reduce the capacity that must be procured by TSOs. To estimate the magnitude of this improvement, the change in forecasting quality for different forecasting horizons may be applied as a rough proxy. For example, the quality of the wind forecast is typically much better one hour before delivery than it is one day before delivery. The difference in the quality of forecasts in different time horizons could thus be applied as a proxy for the reduction in size of the imbalance that has to be handled.

3.2. PRICE CAPS

3.2.1. DISTORTIONS TO BE ADDRESSED

Price caps set an upper limit on the clearing price; correspondingly price floors set a lower limit for prices. Price caps have often been discussed as a culprit for the missing money problem in the capacity market discussion. However, there may be different reasons for setting price caps, for example that demand response that could be used to clear the market is missing, or that they reduce the risk of potential market power abuse in scarcity situations.

There are two possible distortions in relation to price caps. First, the level of the price caps may be suboptimal (too low). Second, price caps may not be harmonized between markets. While the first issue is very difficult to evaluate and depends on a number of factors (value of lost load, capacity situation in each country, etc.), the second one can obviously lead to a biased market outcome in scarcity situations, and hence distort price formation in different countries and market participants' investment incentives.

3.2.2. HOW TO MODEL THE DISTORTIONS

Price caps are easy to address from a modelling perspective, and there are several ways to do so:

- Add slack variables that are unbounded, and that enter the objective function with the cost of a price cap.

- Add virtual plants that start producing at the cost level of the price cap (similar to above, but does not require re-writing the code).

- Adding a step-wise linear demand function and have a step that reflects demand curtailment at the price-cap level. In the model this would cut off the price at the price cap level.

- Address price caps outside the model by evaluating incidents when the model generates prices above the price cap, provided there is slack that ensures that the model solves.

3.2.3. DATA CONSIDERATIONS AND CHALLENGES

To implement this type of distortion one needs to find data on price caps applied in the different markets and countries. For spot markets this type of data is typically available. Otherwise, one can use a common proxy for countries or markets where this type of information is missing. This common proxy could be used on available data for other countries, or on estimates of the value of lost load (VOLL).

3.3. TECHNICAL MARKET SPECIFICATIONS

3.3.1. DISTORTIONS TO BE ADDRESSED

Market outcomes are likely to be distorted if technical product specifications are not harmonized across markets. For example, technical requirements may be different in different markets (size of block bids; technical specification of technologies that can participate, etc.). Such non-harmonized specifications are typically a barrier to cross-border utilization of resources between markets.

In day-ahead markets, technical specifications are often harmonized and do not present a barrier to cross-border utilization. However, in intraday, and in particular in balancing markets, technical specifications and requirements can often constitute a barrier to trade and efficient cross-border utilization of resources.

3.3.2. HOW TO MODEL THE DISTORTIONS

Technical specifications or regulatory differences are sometimes difficult to capture directly in a model. This relates to the fact that any model makes assumptions and simplifications in representing the real world (see Section 3.9).

However, there are indirect ways of addressing this in a model:

- Depending on the specific technical requirements, one can outside the model determine which technologies may or may not participate in different markets.

- Depending on whether technical specifications are harmonized or not, one can allow the model to utilize cross-border capacities or not in the relevant market timeframes.

3.3.3. DATA CONSIDERATIONS AND CHALLENGES

As mentioned above, the technical specifications are often not implemented directly in a model, but rather indirectly by allowing or not allowing utilization of cross-border capacity. It is therefore not one type of data or information that is relevant, but a general assessment of whether or not technical specifications prevent cross-border provision of say balancing services.

For further discussion of the modelling of balancing markets, see Section 3.6.

3.4. CALCULATION AND ALLOCATION OF INTERCONNECTOR CAPACITY

3.4.1. DISTORTIONS TO BE ADDRESSED

As we have seen in chapter 2, day-ahead markets are currently mostly coupled, either via an implicit auction design or via flow based market coupling. While flow based marked coupling is considered even more efficient than implicit auctioning, both models have in common that the use of cross-border capacity is optimized or the result of a market clearing/optimization process.

Even though day-ahead markets are coupled, the cross border capacity available for trade may be suboptimal. There can be several reasons for this: Sub-optimal coupling (explicit or implicit auction instead of flow based market coupling), or too high security margins due to sub-optimal TSO cooperation and cooperation on balancing services.

In other time frames, however, markets are not coupled to the same extent. While some countries have coupling of intraday markets (by implicit or explicit auctioning of intraday cross-border capacities), the utilization of cross-border capacities for balancing services is still an exception. This leads to an inefficient market outcome as the supply of flexibility is restricted to the country or TSO region where the balancing services are procured.

3.4.2. HOW TO MODEL THE DISTORTIONS

Modelling the cross border provision as such is fairly straightforward. The balance equations of a model can be re-written in order to also allow import/exports of intraday and balancing flexibility across borders within the limits of available interconnector capacity. Such provision would have to be backed by generation capacity across the border.

There are different ways to address the utilization of cross-border capacity in different market time frames:

- The allocation of capacity to be used by intraday and balancing markets could be optimized by the model across all time-frames, prior to the simulations. How much the model reserves for balancing then also depends on bid-block constraints (e.g. does capacity have to be fixed for peak hours within a week). The finer the granularity of reservation, the more efficient the solution.

- The model could allocate residual capacity that is not used in day-ahead markets for the provision of intraday flexibility, and capacity not utilized in intraday markets for exchange of balancing services. This is a kind of rolling horizon optimization.

- In both cases, the model could use netting even in case a line is fully utilized. For example, if a line is fully utilized for export, it can still provide downward reserve in an adjacent market, thereby reducing net exports.

Thus, in terms of modelling, the equations of a model can be adjusted to account for cross-border provision, depending on the market design one wants to capture. In the distorted scenario, one would simply restrict trade opportunities for those countries where such restrictions apply.

What is truly challenging is to understand to what extent the removal of these and other distortions, or changes in market design rules, may affect the NTCs or Reliable Available Margins (RAMs) available for trade. This does not only relate to the questions above, but also to other distortions (see e.g. Section 3.5).

3.4.3. *DATA CONSIDERATIONS AND CHALLENGES*

In order to model the distortions related to suboptimal utilization of interconnector capacities, we have gathered information about today's status on cross border provision of intraday and balancing services.

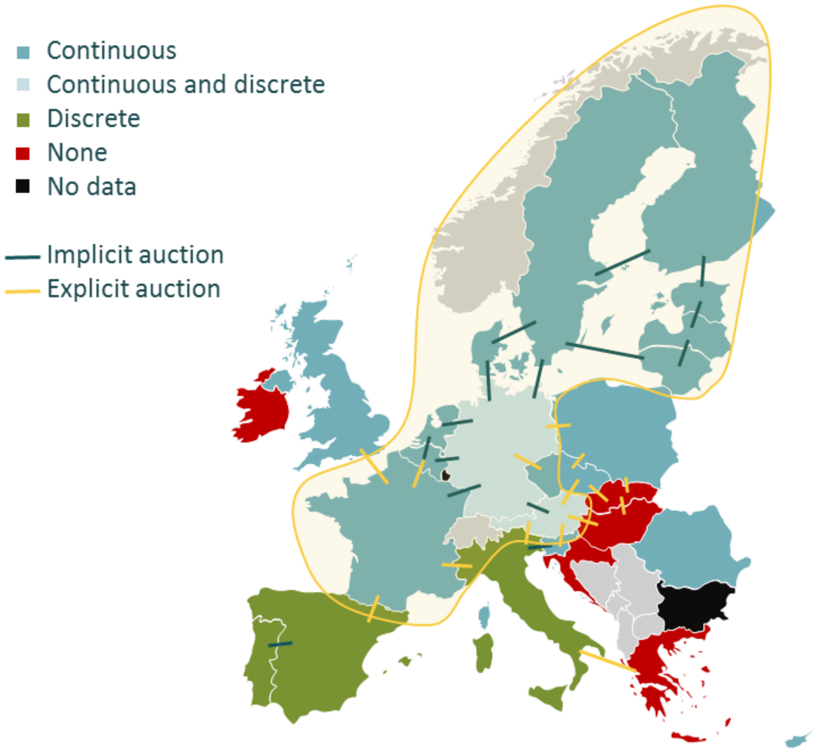
Intraday

The information gathered by the country experts show that most Member States have introduced intraday markets. Intraday market coupling (implicit auctioning) are in place in the following regions:

- EPEX: Germany, Austria, France, Switzerland
- Nord Pool Spot ElBas: Denmark, Sweden, Finland, Norway, Baltics, Netherlands, Belgium, Germany
- MIBEL: Spain, Portugal

Additionally, on a number of interconnections explicit intraday auctioning mechanisms have been implemented, as shown in Figure 17. The figure shows which MS have domestic intraday markets and whether trade is continuous or discrete. Moreover, it shows the interconnections with implicit intraday auction, and the interconnections with explicit auctions. For example, between Belgium and France, there are explicit auctions taking place every two hours (rolling auctions).

Figure 17 Intraday market mechanisms (colors) and the coupling mechanisms (lines).



The explicit auctions occur six times a day, each for four hours. Market participants may submit bids in the period between 6 hours and 2.5 hours before the first auctioned hour (i.e., 9 to 5.5 hours before the last hour in each four-hour block). The offered capacity is updated until gate closure (2.5 hours before the first hour). Capacity is then allocated on a first come first serve basis, and capacities are allocated free of charge. The market is however organized as "rights-with-obligation", meaning that acquired capacity comes with the obligation to use the capacity.

Even for some of the other markets, there appears to be some bilateral intraday trading taking place. This could be, e.g., in the form of a bilateral exchange between self-balancing parties.

If we assume that no intraday exchange is taking place, then the original trades from the day-ahead auction are kept in the intraday auction, and adjustments (imbalances) must be handled by domestic resources. Hence, a way to model imperfect intraday trade, would be to reduce the amount of interconnector capacity that is taken into account in the intraday auction. For explicit intraday coupling, the available trade capacity could be reduced to 50% as proxy to address the inefficiency of explicit auctions in intraday market coupling (unless one has a more precise estimate or method on how this could be captured). In case there is no coupling, the available capacity would be set to zero.

Balancing

Although reserves are normally procured on a national level, there are some notable regional collaborations on exchange of reserves:

- Common FCR market for Austria, Germany, and the Netherlands (and Switzerland).
- mFRR exchange of reserves among France, Spain, and Portugal (each TSO with its own procurement mechanism, no common optimization)
- mFRR exchange of reserves (activation only) among Sweden, Denmark, and Finland (and Norway)

Additionally, there exists a number of bilateral agreements for exchange of reserves with a more limited scope.

In case of these instances, the model can allow trade of balancing services. In other cases, trade capacities can be set to zero. Trade of balancing services can be modelled by allowing exports and imports of balancing services in order to meet balancing requirements. Naturally, such exchange would need to be backed by capacities in the respective countries that export balancing services. The market design (e.g. block bids for balancing services) would need to be accounted for. Depending on the sequence of the optimization, the model could use "free" interconnector capacity that is not utilized in spot markets, or the model can co-optimize trade capacities, depending on what approach would be most suitable. It should be noted that balancing services may be provided even when a transmission line is fully utilized in the day-ahead market, because the country exporting in spot can still provide downward balancing services. This is sometimes referred to as "netting".

day-ahead markets

We have performed some background research to evaluate how NTC values could be adjusted to reflect different market distortions. We divided our analysis into three parts:

- Proxies to model the effect of explicit auction vs. implicit auction (market coupling); such proxies may also be used for modelling different market designs for intraday coupling

- Proxies to model ATC market coupling vs. flow based market coupling

- Proxies to model the transition to a more efficient set-up for flow based market coupling (e.g. improved bidding zone delimitation (see Section 3.5), or regionally coordinated ATC values).

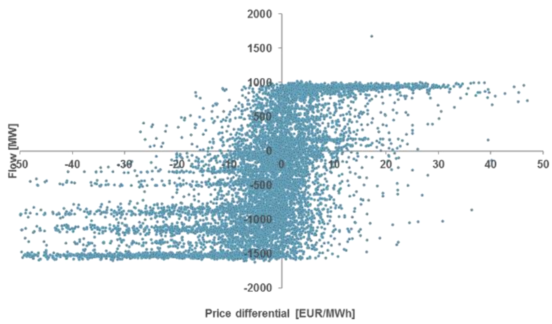
The proxies below should be considered as very rough estimates. As the estimates are highly uncertain, one should consider also sensitivities around these parameters to assess the marginal importance for the outcome.

Transition from explicit to implicit auction

In Member States day-ahead markets are coupled via implicit auctions. That implies that the cross-border market flow is optimized by the day-ahead market clearing algorithm. This is opposed to explicit auctions where the flow is determined by participants buying transmission rights based on expected price differentials.

Explicit auctions imply less efficient market flows. This is illustrated by the graphs in Figure 18 below, showing price differentials vs. physical flows on the DK1-DE border before market coupling, and after the introduction of market coupling. Note that market coupling was introduced November 2009.

Figure 18 Physical flow vs. price differential DK1-DE November 2008-October 2009 (left) and November 2009 to October 2010 (right)



The figures illustrate the challenge with explicit auctions, namely under-utilization of interconnector capacity, or even flows in the wrong direction, in hours where market participants estimate price differential incorrectly. This results in an overall sub-optimal utilization of the cross-border transmission capacity.

If we ignore flows in the wrong direction, and only account for flows if the price differential is higher than 2 EUR/MWh, we obtain a utilization before market coupling of around 60 %, and after implementation of market coupling of around 90 %. Thus, on average, utilization increases by around 30 % points. Using this reduction as a proxy for reducing NTC for those lines that still apply explicit auctions may be one way to model this market distortion.

Transition to FBMC

Flow based market coupling (FBMC) is expected to improve the utilization of cross-border capacity. We have studied historical flow data from 2013 (ATC) and compared it with flow data after FBMC was introduced in CWE. When looking at trade in terms of absolute hourly flow as percentage of hourly balance, FBMC yielded an increased trade as follows: 10 % in Belgium; 23 % in Germany; 26 % in France; 14 % in Netherlands.

However, one should be very cautious drawing decisive conclusions based on these numbers. Changes in trade might be due to a variety of factors (e.g., changes in fuel prices, RES deployment, nuclear availability, etc.), in addition to market coupling. Given the just relatively recent implementation of FBMC (about one year of operation at the time of writing), there is unfortunately little empirical data so far.

Taking these considerations into account, the numbers still indicate an increase in the utilization in energy terms with FBMC compared to the ATC market coupling.

In order to model the distortion, one could use NTC values as reported by TSOs and as forecasted. For the transition to FBMC, the values may be increased by a 10% factor (rough first indicator) to take account of more efficient trade.

Improved regional cooperation and improved set-up

The maximum trade capacities (RAM = Reliable Available Margin) in flow based market coupling are determined by the physical max flow minus a base flow minus the flow reliability margin (FRM) minus a discretionary value.[22] The FRM is a parameter that reflects several risk factors that need to be taken into account by the TSO:

- Unintentional flow deviations due to operation of load-frequency controls
- External trade (both trades between CWE and other regions, as well as trades in other regions without CWE being involved)
- Internal trade in each bidding area (i.e. working point of the linear model)
- Uncertainty in wind generation forecast
- Uncertainty in load forecast
- Uncertainty in generation pattern
- Assumptions inherent in the Generation Shift Key (GSK)
- Grid topology
- Application of a linear grid model

The inherent risk in some of these factors may be reduced by inter-TSO or inter-regional cooperation, and by introducing new bidding zones that reflect bottlenecks (see also 3.5). A main challenge in calculation of Power Transfer Distribution Factors (PTDFs) and RAMs arises from the fact that one aggregates nodes into price zones. A finer granularity of bidding zones would hence improve the accuracy of the underlying PTDFs and utilization of cross border capacities.

Unfortunately, there is not much data available to indicate how much the utilization would increase when bidding zones are optimized. Also, a FAQ document issued by the TSOs indicate that they have no plans of looking into this issue.23 Also, there is no information on the actual size of the FRMs in CWE.

[22] see e.g. https://www.acm.nl/nl/download/bijlage/?id=11810

[23] see https://www.apxgroup.com/wp-content/uploads/FAQ_-_update_121211.pdf; Question B1

In other documentation[24], it is indicated that "FRM values spread between 5 % and 20 % of the total capacity Fmax of the line, depending on the uncertainties linked to the flows on the CBCOs." Thus, there seems to be a range to 15 % in the FRM shares.

Based on this, one may argue that a potential 5 % increase in trade flows could be achieved by finer bidding zone granularity and regional cooperation. This estimate, however, is highly uncertain, and there is no solid data foundation for such an estimate.

One could also argue that the transition to FBMC already represents an increased and more efficient regional cooperation between TSOs as it requires TSOs to cooperate on how cross border capacities are utilized. Before FBMC in CWE, and still practiced in other countries, the NTC on each line is calculated by both involved TSOs, and the actual NTC that is given to the market is the *minimum* of the two respective NTCs. It is likely that a coordinated calculation would increase the NTC value that is given to the market.

Thus a share of the suggested 10 % ATC increase by moving to FBMC can be attributed to increased regional cooperation already, and not only to FBMC as such. Thus, once FBMC is in place, the main additional benefits could lie in moving to a different and more appropriate bidding zone setup (see also section 3.5).

3.5. BIDDING ZONES

3.5.1. DISTORTIONS TO BE ADDRESSED

Currently, only a few countries are divided into multiple bidding zones as a means to handle bottlenecks in the underlying grid (e.g. Norway, Sweden, Denmark). Other countries, like for example Germany, are not divided into price zones, despite obvious bottlenecks in the transmission grid.

Bottlenecks not addressed via bidding zones can lead to multiple challenges:

- *Inefficient dispatch:* If bottlenecks are not represented correctly, a single price for different areas is inefficient, in the sense that it might incentivize too much or too low generation compared to what would be efficient from a market point of view (accounting for network constraints). This often makes the bottleneck situation even worse.

- *Inefficient cross-border trade:* Also along the system borders the price differential gives inefficient trade signals in the case of internal bottlenecks. For example, if the price in a region is higher than what would be efficient from a bottleneck point of view, the import into this region is higher than what would be efficient. Again, this could worsen the bottleneck situation. Also loop flows can increase when bottlenecks are not visible in the DAM solution (NB: introducing price zones does not necessarily imply that loop flows would disappear, but they are likely to be reduced).

- *High re-dispatch costs:* Bottlenecks have to be handled in one way or another, if they are not taken into account in the day-ahead market solution. This often leads to high re-dispatch costs in markets where bottlenecks are present.

- *Improper investment incentives:* With a single price for a zone with internal congestion, prices do not provide locational investment incentives. Strategic behaviour might lead to deliberately investing in the "wrong" location, to

[24] See https://www.acm.nl/nl/download/bijlage/?id=11810

benefit from re-dispatching. With multiple prices, incentives are given to generators to invest in the places with the highest price, which may be where they are paid to relieve congestions.

- *Challenges with flow based market coupling:* In a flow based market coupling regime the cross border market flow is determined by the balances in each bidding zone and by the PTDFs. The aim is to make better use of existing interconnections, by accounting for the capacity on individual lines and Kirchhoff's voltage law. It is a challenging task to go from a nodal PTDF to a zonal PTDF. The zonal PTDF depends, among other things, on where in a bidding zone generation and demand is located. This implies that TSOs have to anticipate where generation and load will be allocated within a zone the next day (through generation shift keys, GSK), in order to provide an adequate zonal PTDF. The larger the bidding zones are, and the more severe the bottlenecks are, the larger are the challenges in calculating efficient PTDF values.

This is also in line with challenges observed in the market, where bottlenecks not addressed in day-ahead markets have led to reduced NTC values, the installation of phase-shifters to alter or avoid loop flows, and increased re-dispatching costs.

3.5.2. How to model the distortions

Modelling bottlenecks correctly is very challenging and requires knowledge about the physical grid. There is often an information asymmetry between TSOs, who often consider this type of information confidential, and market players who may need knowledge of congestions to forecast prices and optimize generation and investment decisions.

Some issues can be addressed by a model, while others are more difficult to capture:

- The bottleneck "size" may be estimated using a simplified grid model. In this respect, however, one needs to be careful in using physical capacities directly as NTC values in the model. DC load flow models may be applied to approximate the physical flows and address bottlenecks. Such models could also be used to calculate re-dispatch costs in conjunction with a typical dispatch model.

- How a finer granularity of bidding zones would impact the efficiency of PTDFs is extremely difficult to capture, as this would require detailed information not only about the grid, but also about how TSOs make their forecasts for day-ahead generation and demand within a region (generation shift keys).

3.5.3. Data considerations and challenges

In our data collection for this project, we have not asked direct questions about the precise location and size of bottlenecks within a region.

In general, we would suggest to address improved bidding zone delineation by adjusting cross-border capacities available for trade. For further details, please see section 3.4. However, due to the complexity of the issue, accurately addressing this question would require a detailed study.

3.6. Balancing reserve Dimensioning, Procurement, and Cross-Border Provision

3.6.1. Distortions to be addressed

For balancing markets there are a number of distortions that are addressed. Roughly, they can be divided into three different issues:

- *The dimensioning of balancing requirements*: The TSOs need to determine how much balancing reserves they would like to procure. There are several factors that influence this variable: The granularity with which market services are procured, the balance responsibility of the different parties, the incentives for accurate forecasting, and balancing of own portfolios, whether balancing is procured from a national or regional perspective, and other factors.

- *The procurement of balancing reserves:* This includes not only whether certain resources are allowed to provide balancing reserves and which resources are excluded, but also how the reserves are procured. For example, is the amount of capacity procured fixed for a given time period (for example, capacity has to be committed for all peak-hours in a week), or does it have a finer granularity (for example, auctioning of capacity for each hour). Note that this is very different from the sizing of the reserve. Even if the sizing in each hour is the same, the procurement determines whether the capacity provided by a participant has to be reserved for a longer time period (several hours) or for one hour only.

- *Cross-border provision:* Balancing services may be procured or exchanged cross-border. In this case, the cost of procurements could be reduced. How much cross-border capacity may be utilized is a different question (optimized by TSOs, residual capacities, "netting" capacities; see also section 3.4).

3.6.2. How to model the distortions

There are several options to address distortions related to balancing reserves in a model:

- The dimensioning of balancing reserves could either be optimized by the model (i.e. it becomes part of the optimization problem), or it is derived exogenously outside the model. In the latter case, one can use other model input data (e.g. forecasting errors, observed deviations) to derive an estimate. In the former case, the advantage would be that changes in market design can be directly translated into a different optimal sizing of balancing reserves.

- The procurement of balancing services can be captured by adding constraints to the model. If, for example, a certain amount of capacity has to be committed or reserved for a block-bid period (e.g. peak hours in a week), this can be reflected by an additional constraint in the model. The more constrained the model solution becomes, the less optimal the market solution becomes. Note that if a commitment for a longer period is required, the opportunity cost for market players to reserve capacities increases.

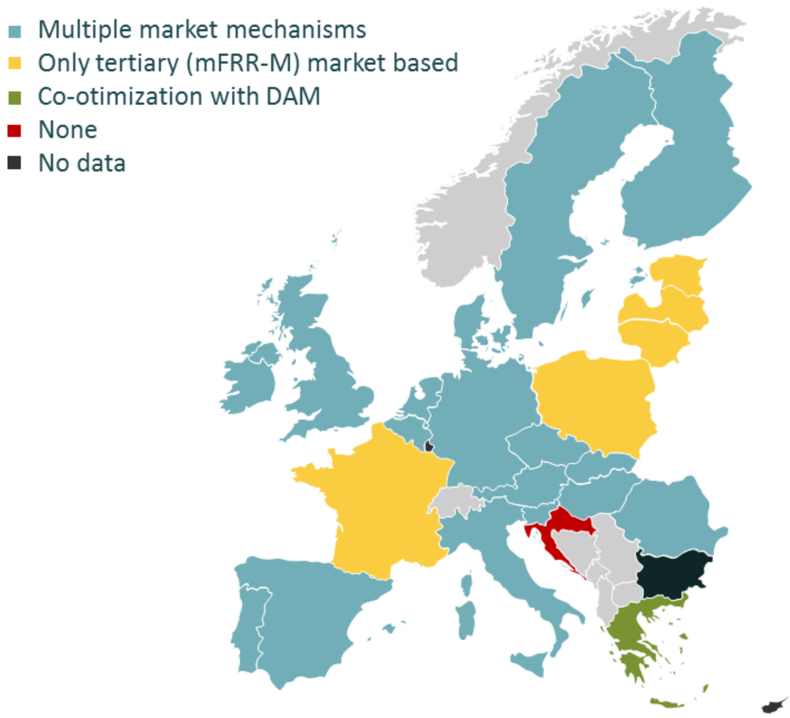
- There may also be symmetry restrictions on reserve provision. For example, in some markets, market players have to provide symmetric amounts of upward as downward reserves. Again, this is easily implemented by linking two variables via a joint constraint in the model

3.6.3. Data considerations and challenges

We have collected exhaustive information on technical requirements, market design, procurement rules and cross-border provision of reserves. An overview is given below.

Most MS have at least one market based procedure for procurement of balancing reserves, as shown in Figure 19. Croatia is the only MS without any market based mechanisms, as balancing reserves are currently procured through bilateral contracts with the TSO. In the Baltic states, Poland, and France, there are only market based procedures for tertiary reserves (mFRR).

Figure 19: Degree of market-based mechanisms for balancing services.



The extent to which balancing reserves are procured through market based procedures, however, varies significantly among MS. The variations are due to:

- Implementation (e.g., a yearly tendering process versus a daily auction, whether compensation is pay-as-bid or marginal pricing, whether the products for upward/downward balancing are separate, etc.)

- What services are procured through market based procedures (e.g., capacity reserves or energy settlement, and primary (FCR), secondary (aFRR), or tertiary (mFRR/RR) reserves)

The main feedback from the country experts can be summarized as follows:

- Significant obligations: Some MS have requirements for certain technologies to provide balancing services. In France for instance, there are requirements to provide both FCR and aFRR reserves, and the compensation is a regulated price. Several MS have mandatory provision of primary reserves (FCR) for certain generators. There may be secondary markets to exchange reserves bilaterally, but such mechanisms are far from optimal. In Italy and Portugal, generators are obliged to provide primary reserves without any compensation. In some MS there may be an obligation to participate in the market, which is less strict than the former case, because the market participants are allowed to specify a price (although possibly within a restricted range) associated with a bid, and a market based mechanism is used to determine what bids are accepted.

- Significant barriers: There are several barriers to participate in the balancing markets, most commonly for demand side response and/or RES generation.

- Procurement frequency: We have obtained some information on whether the procurement frequency is "optimal" or not. We consider the procurement more "optimal" if a TSO procures reserves frequently. For example, a TSO may contract parts of the reserves on a yearly basis. Adjusting the reserves according to short-term needs on, e.g., a weekly basis, clearly improves the efficiency or the sizing of the reserves. However, if a TSO contracts the entire reserve on an annual basis (and leaves this unchanged), we assume that the sizing will be sub-optimal. As the need for reserves varies over the year, a TSO procuring reserves on an annual basis only is likely to over-dimension the reserve, and is likely to exclude certain resources from the market. In MS where the reserves are procured less frequently than monthly, the sizing may be considered non-optimal. Most MS procure reserves quite frequently. Notable exceptions are Poland, Slovenia, the Netherlands, the Baltics, Finland, and Sweden.

We did not obtain good information on how often the dimensioning of the reserve is conducted. Ideally, the sizing should be done hourly. However, we suggest to use the procurement frequency and granularity as an indicator on the optimality of the sizing.

In general, balancing reserves are mainly dimensioned and procured on a national level. However, the dimensioning of *primary* reserves is to some extent regional, that is:

- A minimum requirement of 3000 MW of primary reserves in the Continental European synchronous grid is required by ENTSO-E, and each country must provide a share corresponding to its share of generation in the synchronous grid.

- A minimum requirement of 600 MW of FCR normal operation reserve, and 1200 MW of FCR disturbance reserve is required in the Nordic synchronous grid.

- There are no primary reserves in the Baltic region, as primary control is conducted by Russia.

Dimensioning of secondary and tertiary reserves (FRR) is based on national assessments. We did not identify any MS conducting a regional assessment of reserve requirements for FRR.

Although reserves are normally procured on a national level, there are some notable regional collaborations on *exchange* of reserves (see also 3.4.3):

- Common FCR market in Austria, Germany, and the Netherlands (and Switzerland).

- mFRR exchange of reserves in France, Spain, and Portugal (each TSO with its own procurement mechanism, no common optimization)

- mFRR exchange of reserves (activation only) in Sweden, Denmark, and Finland (and Norway)

Additionally, a number of bilateral agreements for exchange of reserves with a more limited scope exist.

The product definitions vary significantly among MS. Differences include the minimum bidding size, price caps, symmetrical versus asymmetrical products, time schedules, marginal pricing versus pay-as-bid compensation, and other elements.

3.7. DEMAND RESPONSE

3.7.1. DISTORTIONS TO BE ADDRESSED

Demand response in power markets is currently still limited. There are several reasons for that. First, not all demand is exposed to hourly metering and hence there is a lack of incentive to actively adjust demand. Second, demand response may be prevented from participating in certain markets, or may be exposed to incorrect price signals. For example, an end-user with some flexible own generation, typically needs to pay the wholesale electricity price plus levies and taxes when consuming electricity from the grid. Thus the producer may only shift from own generation to consumption from the grid when the *end-user retail price* is below his or her marginal cost of generation. However, when looking at a short-term system perspective, it would be beneficial if the end-user consumes from the grid if the *wholesale price* is below his or her marginal cost of generation.

There may also be technical barriers and economic barriers to demand side participation, but these are not necessarily distortions as such. They rather relate to the economic and technical viability and competitiveness of demand response.

3.7.2. HOW TO MODEL THE DISTORTIONS

Demand response or the absence of demand response is fairly straightforward to model. By parametrizing a flexible demand curve (either via a functional parametrization, or a stepwise function) and adding consumers' surplus to the overall objective function, demand response can be captured in fundamental models. Demand side management or small scale batteries can also be approximated by modelling similar to conventional storage units.

In addition, one can add restrictions for demand response, as for example restrictions on how long and how often demand response can be provided.

3.7.3. DATA CONSIDERATIONS AND CHALLENGES

The actual challenge in addressing demand response is not so much the model implementation, but rather the access to appropriate data. The data for evaluating the actual relevant potential for demand response is still very limited.

However, the demand response potential has been addressed in a separate study that was conducted in parallel to this study (see footnote 2). As part of our data collection, we gathered more generic information on whether or not demand response can participate in certain markets or not, and what the possible barriers are (see chapter 2).

3.8. CURTAILMENT

3.8.1. *DISTORTIONS TO BE ADDRESSED*

In case of imbalances, and in case these cannot be covered by balancing markets, the TSOs may have to curtail generation when supply exceeds the demand. In an ideal market, this kind of curtailment would be cost based, taking also into account start-up costs and other considerations.

A distortion occurs if the order of curtailment is sub-optimal and not cost based. For example, instead of curtailing a thermal power plant and incurring high start/stop cost, it may be economically much more efficient to curtail part of a wind farm. This, however, may not be feasible due to certain regulation or other technical barriers.

There are two types or reason for curtailment:

1. Oversupply: After the market resources have been exhausted, ther may still be excess supply. In this case, the TSOs have to curtail generation in order to balance the system.

2. Local grid issues: There may be some local grid issues related to curtailment. The TSO may need certain units in certain areas to operate for reasons of grid stability and security. In this case, the TSO may ask a certain plant to operate at a certain level while curtailing generation somewhere else in the system.

3.8.2. *HOW TO MODEL THE DISTORTIONS*

Of the two types of curtailment described above, modelling the second one would require a detailed grid model. Only the first type of curtailment can be captured by dispatch or market models.

In dispatch or market models, curtailment can be modelled by adding slack variables, or by defining certain costs or penalties that apply when curtailment occurs outside balancing markets. In general, one can distinguish:

- Voluntary curtailment: In this case, the curtailment costs should be close to the marginal costs (including start/stop costs) or the market price. An interpretation of voluntary curtailment is in a way a bilateral extension of the balancing market between the TSO and market participants, i.e. market participants agree to be curtailed if needed in exchange for compensation at market price or marginal costs.

- Involuntary curtailment: In this case, the curtailment costs are at the discretion of the TSOs. Costs are likely to be much higher than in case of voluntary curtailment as they the result of a negotiation between TSOs and probably selected generators. Being compensated at market price or marginal costs is in a way the “worst case” or starting point for negotiations for generators.

If in fact there is a suboptimal curtailment sequencing of technologies for involuntary curtailment, this can be modelled by applying curtailment costs that represent this order. The higher the cost of curtailment, the further down a plant type is in the curtailment sequencing.

3.8.3. *DATA CONSIDERATIONS AND CHALLENGES*

In general, curtailment rules are often not transparent, neither when it comes to under what circumstances TSOs starts curtailing, nor when it comes to the curtailment order (of RES, thermal, interconnectors, and demand). It is therefore difficult to estimate concrete proxies for involuntary curtailment costs.

When it comes to grid issues, one way of representing that TSOs may order thermal units to generate instead of cheaper RES due to grid issues may be to constrain those thermal plants that are scheduled in day-ahead markets to also be operational in the hour of operation (i.e. operating at least at minimum stable load). Thus, once scheduled, the thermal plant is only flexible within the bounds of operation, but cannot shut down. Any excess supply after balancing and intraday takes place has hence to be taken via other sources.

3.9. Concluding comments on Modelling and Data considerations

In the above section we have outlined how distortions may be captured in modelling by adding additional model constraints (e.g. limiting cross-border provision of reserves), or by implementing data that reflect these distortions (e.g., price caps).

Thus, modelling distortions (or the removal of distortions) faces two major challenges:

- *Complexity*: Every model is a brute simplification of reality. Thus, a model is not in itself able to capture all features and facets of reality. While one may be tempted to include as many features and options as possible, one has to be careful in order to avoid over-complication of models. To high complexity can very quickly result in overfitting (i.e. modelling relationships and cause and effects that do in this way not apply to reality, but yielding a better fit), and transparency issues (i.e. in the end not understanding the model results, or drawing wrong conclusions). It is therefore essential to find the right balance between complexity and transparency, taking the main aim of the model into account.

- *Data*: Data challenges are as important, and often represent a major bottleneck in model-based analysis. Very often, the methodology of modelling market aspects is fairly straightforward, but the data is simply unavailable or undisclosed. It is therefore important when setting up a model, to be aware of the underlying data accessibility, the quality of data, and options of using "default" proxies that may be applied if data is missing.

In the end, all modelling efforts are a compromise between the complexity of the model, the underlying data quality, and the purpose of the model. In this respect, it is important to be aware of a model's limitation, both in terms of methodology, but also in terms of its data foundation.

4. IMPACTS AND MODELLING OF POLICY MEASURES

In this chapter we discuss the policy measures that may be implemented in order to reduce or remove the identified distortions, their expected impact on the efficiency of the electricity market as a whole, and comment on related modelling issues, based on the analysis and recommendations in chapter 3.

In principle, the assessment of the impact of measures that reduce or remove the identified distortions could be analysed one at the time. However, the impact of one measure may be significantly affected by other measures, and in some cases several measures should be implemented simultaneously in order to achieve the desired effects. Therefore, we have grouped the measures in broader categories, depending on what distortions they target:

1. Measures to create a level playing field for all (relevant) resources
2. Measures to increase the efficiency of price formation in the market
3. Measures to optimize ATC calculation
4. Measures to facilitate and increase cross-border trade in intraday and balancing markets
5. Measures to provide regional sizing and procurement of balancing resources
6. Measures to increase the participation of demand-side resources

For each of these groups of measures we discuss the expected impacts and modelling issues below.

4.1. CREATING A LEVEL PLAYING FIELD

Creating a level playing field implies removal of distortions related to:

- Priority dispatch (non-technical)
- Market access (all market timeframes)
- Exemptions from balance responsibility
- Involuntary curtailment of resources

Today, some resources are explicitly prioritized for technical and/or legal reasons, or implicitly prioritized in the merit order due to the design of RES support schemes or other policy targets. For example, Feed-in Tariffs imply that RES generation is not exposed to market prices, thus will implicitly be dispatched at any (even negative) price. Similarly, RES supported by Feed-in Premiums will be dispatched at negative prices as long as net revenues are positive when the premium is taken into account. The same incentives apply to support in the form of green certificates as well. Creating a level playing field implies that distortive RES support schemes are abolished so that RES resources are exposed to, and have an incentive to respond to, market prices. It should be noted that a fully levelled playing field in short-term markets implies that RES generation does not receive energy-output related subsidies or non-market based revenues.

Discussion of the measures

Resources may be explicitly *not allowed* to participate in the markets, or there may be (in)direct barriers to participation due to technical or economic requirements (e.g.

market product characteristics). If resources are not allowed to participate in the markets or market products are defined in such way that they do not suit certain resources, these resources will not respond to market prices. Concrete measures imply that unnecessary technical and economic barriers are removed or reduced, and that products are reviewed in order to accommodate RES participation, including in the intraday market and Balancing markets. However, if intraday and balancing markets are not liquid or not transparent, the access may not affect costs and revenues of RES generation in this option.

Balance responsibility is probably a precondition for the effect of removing priority dispatch. If market participants are not made BRPs or do not have the obligation to assign a BRP, they may still bid in a manner that implies priority dispatch (as they are not penalized for imbalances), or simply nominate expected generation as before (unless market participation is mandatory). By making RES generation balance responsible, they get a stronger incentive to participate in the market, and to bid (or nominate) as precisely as possible.

Balance responsibility implies a cost. The cost can be high for intermittent RES resources, for which it is difficult to accurately predict day-ahead generation. Access to day-ahead and intraday markets could however enable them to manage these costs more efficiently. Access to the intraday market enables RES suppliers to adjust balances after day-ahead gate closure as predictions become more accurate. If intraday markets are not liquid, RES generators will have an incentive to contract with other players who have flexible generation in order to manage changes in expected balances after DAM gate closure. The alternative is to be fully exposed to the imbalance costs accruing from the Balancing markets of the TSO.

However, even if intraday markets are not liquid, the balance responsibility should incentivize RES generators to improve the accuracy of their forecasts, thereby potentially reducing unforeseen imbalances in real time in the system, and consequently, imbalance costs.

Curtailment implies that the market solution is overruled by the TSO.[25] The reason may be that the equilibrium according to bids and nominations in the day-ahead market is not achieved, or that sufficient resources are not available in the balancing market. While market participants implicitly volunteer curtailment via flexible bids, and thereby also reveal their curtailment cost, resources with priority dispatch, without balance responsibility and without access to the markets, do not place flexible bids in the DAM. The DAM algorithm may fail to find equilibrium either due to excess generation or due to excess demand. The issue of curtailment of generation is associated with the first, i.e. with excess generation and zero or negative prices. If negative prices are allowed, the market should normally be able to find a solution with voluntary curtailment. As such, this measure is linked to minimum price caps: If prices are not allowed to be negative, the day-ahead market solution will not curtail generation based on market bids (merit order).

We can therefore expect that curtailment is more likely to be an issue related to the balancing of the system in real-time, and in particular in cases where the generation

[25] Curtailment could be necessary due to grid issues as well, but here we focus on the functioning of the markets and curtailment that is carried out in order to manage excess supply in real-time. The distinction between market-induced and grid-induced curtailment is not clear-cut in practice. For example, curtailment can be due to bottlenecks within a bidding zone (grid-related) or due to congestion between bidding zones (market-related).

from must-run generation or generation with priority dispatch turns out to be higher than the level anticipated at DAM gate closure. If BA resources are not sufficient to manage these imbalances, curtailment is necessary to balance the system. If curtailment is not market based, i.e. carried out according to least curtailment cost, the TSO must follow administrative or technical procedures for curtailment, which are not necessarily efficient. Specifically, the least-cost option for involuntary curtailment is probably to curtail renewable generation with low start-stop costs.

In addition, although not really allowed, one suspects that TSOs sometimes curtail interconnectors in order to reduce domestic curtailment and internal counter trading or re-dispatch (see chapter 2).[26] If such curtailment is done prior to the day-ahead solution, by reducing ATC values for day-ahead (and intraday) trade, it affects price formation and long-term investment signals in the market.

The inefficiency of involuntary curtailment is further exacerbated if curtailment is not compensated according to market-based principles, because this could create missing money problems for the providers of curtailment and could discriminate between resources.

As the share of renewable electricity increases, situations which call for involuntary curtailment may become more frequent if measures such as the ones proposed above are not taken.

Expected market results

These measures should lead to more efficient price formation in DAM and reduced system operation costs related to handling of RES imbalances. The main reason is that RES generators get stronger incentives for more accurate forecasting, and that the DAM and BA dispatch will follow the merit order of generation more closely. The RES generation that no longer enjoys priority dispatch, will place bids based on marginal costs and will be curtailed voluntarily according to the merit order of capacity. Hence, in some cases with temporary excess supply, RES will enter the merit order after thermal units with start/stop costs due to technical limitations, and the dispatch will be more efficient than in the distorted scenario (cf. chapter 3). This should apply both to the DAM and the BA market.

In combination with Feed-in tariffs being phased out, RES generation is incentivized to place flexible bids in the market, thereby reducing the frequency and magnitude of negative prices.

The liquidity in existing intraday markets should increase, but the proposed measures may not be sufficient to spur significant increases in IDM volumes without further measures to increase the make the market more accessible in terms of product definitions and introduction of aggregators and demand response, as well as measures to increase interconnectivity and coupling with neighbouring markets. Some RES imbalances may even be handled prior to real-time via bilateral arrangements if that is more attractive than taking the imbalance cost from the BA market. If so, the reserve requirements of the TSOs may also be somewhat reduced.

Modelling issues

In terms of the modelling setup, the principles for implementing the measures in order to compare the outcome with that of the distorted scenario are the following:

[26] The Swedish TSO used this practice prior to the implementation of internal bidding zone delimitation, which came about after a complaint by Denmark to EU authorities.

- Removing must-run and priority dispatch can be accounted for by changing the constraints in the model and the associated costs for the different technologies. Instead of running with fixed generation profiles (e.g. in case of FiT) or negative generation cost (e.g. in case of FiP), technologies are modelled with their actual marginal cost and their technical restrictions (start-up costs and constraints).

- Market access can be addressed by allowing technologies to participate in certain markets, where they were not allowed to do so in the baseline scenario. Again, this is accounted for by changing the constraints in the model, in this case which technologies can or have to participate.

- Making parties balance responsible can be accounted for by adding the respective technologies as part of the intraday and balancing markets. However, the more difficult part is to estimate how this may affect the size of the balancing market. Unless the balancing size is a function of the model and a result of the optimization problem, one would need to assess outside the model how this could impact the size of the balancing market. As balance responsibility can be interpreted as a kind of improved generation forecast, one way of addressing this could be to study how forecasting errors develop once one gets closer to the hour of operation.

- Changes in curtailment rules can be addressed by adjusted generation constraints in the model and by changing the costs associated with different slack variables.

4.2. Improved Price Formation

In order to avoid limitations on market price formation, distortions related to price caps should be removed. To further improve price formation and in particular to ensure scarcity pricing, unduly low price caps should be removed. It may is however also important to make sure that minimum price levels are not set to high, in order to incentivize efficient voluntary curtailment in surplus situations. Preferably, price caps should be harmonized across member states.

Discussion of the Measures

The assumption on demand side participation is linked to the issue of price caps. Since demand side participation is limited, price caps reflecting VoLL should help the market establish efficient scarcity pricing.

As we have seen above (chapter 2), the price cap in most markets is set as a technical measure by the exchanges, in order to avoid extreme prices due to errors in the calculations or in the submitted bids. According to market theory, the price cap should be set so high, that it does not represent a focal point for tacit collusion among market players. This also means that the price caps should normally not be binding. Price caps in existing markets in Europe have been increased several times, and generally, when markets have been coupled, price caps have been harmonized.

When it comes to setting price caps, there is a trade-off between ensuring efficient scarcity pricing and protecting locked-in or price insensitive end-users against unreasonably high prices. The idea of price caps reflecting VoLL, is to let prices form as if demand response is generally participating in the market (which it is not, by assumption, in this option). However, a challenge with associating price caps with VoLL, is that the VoLL varies between countries, over seasons and between hours. Hence, it is not clear what this requirement will mean in practice.

Theoretically correct VoLLs should reflect the VoLL of consumers that cannot participate in the market, as one should expect that the VoLL of the rest of demand is represented by the bids in the market. In principle, demand is represented in the market either directly via incentive-based DR schemes, or indirectly if they are exposed to market prices (Time of Use or Real-Time Pricing). Since the level of demand-side participation in markets and incentive-based schemes, as well as exposure to market prices, vary between markets, this is yet another reason why the relevant VoLL varies between markets.

In theory, the VoLL rule for price caps probably implies different price caps in different markets. Hence, price caps according to VoLL may distort trade in coupled markets. Hence, the price caps should rather be based on a more technical measure, but should not be lower than expected peak load VoLL estimates. (For simplicity, price caps could be set at the same level everywhere, e.g. the current 3,000 €/MWh in most markets, or higher, e.g. at 15,000 €/MWh.)

If the demand side becomes more active in the market, as this is also a policy objective and important for efficient price formation, the price cap should be set sufficiently high so that the market solution can reflect the true VoLL via demand side bids.

Too high minimum prices increase the probability of administrative, involuntary curtailment of resources in surplus situations, which again increases the risk that curtailment will not be carried out according to the merit order. This increases the cost of curtailment and distorts market price signals.

Expected Effects

Setting adequate price caps, including for minimum prices, should further improve the efficiency of price formation in the markets, thereby catering for increased short-term efficiency and improved long-term investment incentives.

Modelling Issues

Changes in price caps are easily addressed by changing the values for the respective variables in the model.

4.3. Efficient ATC Calculation

Creating a level playing field and removing inefficient price caps will improve the efficiency of national markets. The efficiency of cross-border trade, does however, also depend on the efficient utilization of cross-border capacity.

ATC calculation can be made more efficient by implementing:

- Regional calculation of ATC values
- More efficient bidding zone delimitation

Discussion of the Measures

Inefficient and non-transparent calculation of ATC values has been identified as a market distortion. Hence, measures can be taken to make sure that the calculation of ATC values to be made available for the day-ahead market is made more efficient. To accomplish this, ATC values should be calculated on a regional basis. Another measure is to make sure that ATC values are not reduced due to internal bottlenecks and grid issues. Hence, introducing bidding zones that follow the structural bottlenecks in the system is also likely to contribute to more efficient ATC values.

For the exchange of day-ahead resources across borders, the TSOs determine the capacities that are made available for cross-border trade. Without flow-based market coupling, the ATC values are set prior to day-ahead gate closure, and are entered into the market coupling algorithm (in coupled markets). The interconnectors have a maximum technical capacity, but TSOs can set ATC values lower than the technical capacity. The reasons for reduced ATC values can be loop flows, expected internal congestions, and reduction of associated counter trade costs. As the ATC values have to be based on expected market flows, the TSOs may also be prone to implement (conservative) security margins. Notably, if the determination of ATC values is not coordinated between TSOs, or optimized across all interconnectors, the under-utilization of interconnectors may be substantial. The result is that trade flows are reduced and price differences between market areas are increased.

This measure implies that the calculation of ATC values is coordinated across market regions, thereby taking advantage of all information available among the regional TSOs, and also taking into account the interrelationship between different interconnectors. As a result, more interconnector capacity could be made available to the market(s) and resources could be utilized more efficiently across regions. Thus, total system costs should be reduced.

A related measure is to delimitate bidding zones based on grid configuration criteria rather than according to national borders. Although to a large extent the European grid has historically been developed within the limitation of national borders and fitted for the configuration of national generation and consumption, there may still be severe internal bottlenecks within control areas as circumstances change. Without more efficient locational price signals, internal bottlenecks may be expected to become more severe as the transition of the energy system progresses.

More efficient bidding zone delimitation implies setting bidding zones that reflect systematic bottlenecks, including bottlenecks within member states and within control areas. This measure should enhance price formation and locational signals in the day-ahead market further, thus directly affecting price formation and investment signals. Moreover, the cost of re-dispatching should be reduced and become more transparent, as “re-dispatching” would be included in the day-ahead solution. In combination with allocation of available interconnector capacity (capacity not used for day-ahead exchange) for other timeframes, this should cater for still more efficient use of resources, more efficient trade, more efficient ATC determination, and more efficient investment signals.

Expected Effects

In the day-ahead market, the utilization of interconnector capacity could increase substantially due to more efficient ATC calculation. This should cater for reduced price differences between markets, increased trade flows and more efficient utilization of available resources. The total need for generation capacity should be reduced, and the full-load hours increase for flexible generation.

Modelling Issues

Changes in market design such as regional cooperation and better bidding zone delimitation may be represented in the model by setting higher ATC values (or higher remaining availability margins, RAMs, in flow-based market coupling). ATC and RAM values are typically provided by the TSOs, based on detailed grid modelling. Models which do not include a detailed representation of the grid cannot optimize or provide ATC or RAM values as an output. Thus assumptions must be made outside the models. (See also section 3.4.)

4.4. More Efficient Cross-Border Intraday and Balancing Trade

In order to make the most of the interconnector capacity, measures could be taken to facilitate cross-border trade in all market timeframes. Measures to accomplish this include harmonized technical market specifications, and more efficient utilization of interconnector capacity across market timeframes.

If features such as price caps and product definitions are not the same, the exchange of resources across markets will not be seamless and effective. In order to increase market integration and efficiency across national borders, the rules for participation, gate closure times and products should be harmonized, in all market timeframes. Hence, efficiency requires that technical market specifications are harmonized. This issue mainly applies to intraday and balancing markets.

In addition, remaining interconnector capacity, not used for day-ahead trade, and capacity that is freed up due to balancing trades, could be made available to the intraday and Balancing markets.

Discussion of the Measures

In principle, trade can take place even though different rules apply in different markets. However, different rules and requirements could be a significant barrier to efficient trade. Harmonizing the technical requirements, the gate closure and the products make it possible to trade across a common exchange platform, so that trade can take place without special arrangements or via bilateral contracts. In addition, common product specifications also facilitate bilateral trade.

Harmonized gate closure times implies that all market participants can act on the same information, and caters for a level playing field between participants located in different bidding zones. When it comes to technical requirements for participation, this is not a prerequisite for trade per se, but this also ensures that all relevant resources are able to participate in the market(s) on the same conditions. All differences in conditions (which implies either differences in the cost of participation or constitutes barriers to participation) distort investment signals, as equal resources are treated unequally depending on location.

Liquid regional intraday markets are unlikely to develop if products are not harmonized (cf. e.g., the Nordic Elbas market). Hence, harmonizing the technical market specification is likely to be crucial in order to utilize the transmission capacity optimally, in order to increase the liquidity in the intraday markets, and in order to share flexibility resources across regions, cf. the next measures. A common specification of balancing products should similarly facilitate the sharing of resources across control areas.

Liquid intraday markets may depend on access to cross-border trade. Ideally, the allocation of interconnector capacity should be made according to the market values. Hence, measures should be taken to make transmission capacity available for exchange in the intraday market.

Such allocation does however imply that the allocation is made prior to or as part of the day-ahead solution. In both cases, the value of intraday trade and exchange of BA resources must be based on expectations. It is easy to get things wrong, thus reducing the value of DAM trade without accomplishing net benefits from intraday trade and BA exchange.[27] Until satisfactory methods and procedures are developed

[27] Some experience from allocation of interconnector capacity to exchange of balancing services was gained in a pilot project jointly conducted by the Norwegian and the Swedish TSO in 2015, the so-called Hasle pilot.

that promise to increase the overall value of trade, the proposed measure is to make ATC capacity not used by the DAM available for intraday exchange, and to update capacities as intraday trades take place.

Today, intraday markets are not well integrated across Europe, with some exceptions (cf. chapter 2). By coupling intraday markets, the liquidity in intraday trade should increase, particularly in well-connected regions. Liquid intraday trade should make it possible to reduce balancing costs, thereby also taking advantage of the extended balance responsibility (cf. Option 1).

Sharing flexibility resources and taking advantage of different profiles of renewable electricity generation across larger regions may be crucial for the possibility to reach ambitious targets for the share of renewable electricity generation, and to do so in an efficient way. By activating flexible resources in the timeframe between day-ahead gate closure and real-time (the timeframe of TSO procured resources), the cost of imbalances and the size of TSO balancing reserves is expected to be reduced, while at the same time, flexible resources which require longer notification times (or have lower costs of activation with longer notification time) can increase their revenues from the market.

Liquid intraday markets should also reduce the size of the reserves that the TSOs need to procure, as they increase the participants (BRPs) opportunities to trade imbalances before real-time operation.

Expected Effects

Cross-border intraday trade made possible by harmonized market rules and access to ATC not used in DAM, should cater for significantly increased intraday liquidity. Flexibility from resources not necessarily active in the balancing market should be more efficiently utilized in the intraday market, which, in combination with the sharing of resources over larger areas (interconnected regions) should bring the cost of system reserves down.

Modelling Issues

In terms of modelling, the removal of the distortions can be addressed as follows:

- Cross border provision in intra-day and balancing markets can be included by re-writing the respective constraints in the model to account for imports and exports for these markets, to be “backed” by respective capacities in the respective countries. So called “Netting” effects can then also be taken into account. For example, if a transmission line is on full export, it may still be used to provide downward reserve in the market it exports into.

- Harmonizing the product definitions and market specifications can be translated into defining which technologies can participate in the different markets. These are then also able to provide cross-border services.

4.5. Regional Sizing and Procurement of Balancing Reserves

More efficient utilization of cross-border interconnector capacity and regional resources can be achieved by measures taking advantage of the available interconnector capacity in order to reduce the total need for balancing resources on European power system level through regional sizing and procurement. Measures to this end include regional assessments of the need for balancing reserves, harmonization of balancing products, and coordinated procurement and activation of balancing reserves across interconnected TSOs' control areas.

Discussion of the Measures

TSOs are responsible for the real-time balancing of the system. To that end, they depend on having sufficient resources available for balancing in the operating hour. As explained in chapter 2, this may imply that they pay capacity for the obligation to place bids in the BA market or to be available for balancing. (Alternatively, TSOs may rely on short-term bidding of activation only, or a combination of the two.) Although TSOs do share balancing resources, and some practice imbalance netting across interconnectors, they tend to determine the volume of balancing resources they need to reserve, based on a national point of view. Thus, the reserved resources may be activated due to imbalances in adjacent areas, but the possible exchange of resources is not necessarily taken into account when the reservation volume is determined.

Again, the measure to harmonize gate closures, product definitions and technical requirements is very much linked to this issue. TSOs need to be sure that if they share resources across control areas, the provision from within and the provision from outside the control area are indeed perfect substitutes, provided that the relevant interconnectors are not congested. Hence, the assessment of the need for reserves must take location into account, but that is even true for national reserves. Hence, there should be a significant scope for more optimal reserve sizing and procurement via regional approaches.

Expected effects

By implementing regional assessments of the reserve needs, the total size of reserves is likely to be reduced and procurement and activation is expected to become less costly. Hence, sharing of balancing resources between TSOs should cater for lower balancing costs and reduced need for TSO balancing reserves.

The need for balancing reserves can be decomposed as follows (related to hourly imbalances, i.e. disregarding the TSOs need for reserves to handle variations within the operating hour, or balance responsibility on a finer time resolution):

1. Participation and liquidity in the DAM and intraday markets. The participation and liquidity is again a function of:

    a. Balance responsibility, which provides an incentive to participate, and in particular for RES and DSR, an incentive to procure flexibility from the intraday market. This could also incentivize them to offer flexibility when possible, as they are already active in the market.

    b. Product definition and market rules facilitating such participation and the general efficiency of the market set-up (gate closure, price caps, continuous trade)

    c. Market integration and intraday trade, implying that more imbalances can be handled in the intraday market

    d. Increased trust in the market participants' ability to handle balancing prior to the operating hour, and thus less distortive TSO practices when it comes to reservation of capacity and re-dispatching out of the market units.

2. The sharing of resources and coordination of reserve sizing:

    a. Regional dimensioning

b. Daily or more short-term procurement

c. More efficient ATC calculation

Hence, implementing all the measures discussed above, three major changes occur which affect reserve sizing:

- Harmonized intraday products and market integration should increase intraday liquidity and implying that a significant chunk of imbalances related to forecast errors can be handled by intraday trade.
- Trading volumes are expected to increase due to more efficient ATC calculation and utilization, which has a similar effect.
- Reserves are shared and calculated regionally, which is different than the above, because it does not really mean that each TSO has a lower reserve requirement, but that part of the reserve requirement can be covered by exchange of reserves. Thus, the total cost of reserves on European level should be reduced.

4.6. INCREASED PARTICIPATION OF DEMAND-SIDE RESOURCES

While the measures above should cater for more efficient utilization of generation resources across market areas and market time frames, the efficient dimensioning and operation of the decarbonized electricity market probably also crucially depends on the active participation of demand response.

Moreover, with demand response adequately represented in the market, price caps no longer need to reflect the value of lost load as the willingness to flexibly adapt demand, and its corresponding cost, will be revealed in the market. Potentials for increased demand-response and measures to activate demand-response is analyzed in more detail in the downstream flexibility study (see footnote 2).

Expected results

Removing market distortions with respect to market access in all market timeframes would create a level playing field. Dealing with current market distortions implies different possible gradations or levels. A distinction can be made between "allowing" or "not forbidding" a market access on the one hand, and real market facilitation[28] on the other hand.

Removing certain access distortions could for instance refer to allowing demand response and storage to offer services in the market *in a first stage*. In practice, quite some day-ahead markets do not forbid these resources to be offered to the market (e.g. implicitly through aggregation of bids), although the product specifications might not necessarily be very suitable for these resources and somehow might implicitly discourage their market integration. Nevertheless, there are market segments where resources are explicitly excluded from entering the market. For instance, in a number of countries (see Figure 11), demand response and/or RES is explicitly not allowed to offer specific ancillary services to the TSO. Removing this distortion in the first place means that this explicit prohibition is removed, assuming that these resources have

[28] Not to be mixed up with active support (e.g. subsidies and/or other direct incentives).

the technical capabilities to provide services in line with the product/service definitions.

In *a second stage*, one could go a step further by actively facilitating the market in order to create more liquidity or to "create" the market, without having the need to actively support certain resources or technologies. An illustration of this tendency is the recent evolution of emerging demand response services in Belgium (see text box).

> *In 2013, the Belgian TSO allowed explicitly aggregation of loads to be offered for load interruptibility services (one of the oldest load response ancillary services[1]). In addition, the same TSO developed a combination of asymmetric and symmetric R1 or Frequency Containment Reserve products in order to make it possible for demand side to participate and in 2014, the same TSO allowed aggregation from resources connected to the distribution grid.*
>
> *The creation of these possibilities and the anticipation on possible services by demand response, by taking into account technical specifications from these resources, led to the creation of a demand response market and emerging business by flexibility service providers. The same evolution put pressure on existing traditional (generation) flexibility providers and the prices asked for the respective ancillary services contracted by the TSO. The evolution of redesigning ancillary service products is still ongoing.*

When it comes to neutral market facilitation, also the role of distribution system operators is expected to change in order to enable a better integration of demand response resources connected to the distribution grid into the power system and the market[29]. Depending on the degree of "pro-activeness" this could lead to further allowance or even real market facilitation of demand response solutions.

Modelling Issues

As described in chapter 3, there are several ways of modelling demand response, ranging from modelling elastic demand (stepwise constant function, non-linear) to including virtual plants that reflect the technical parameters around certain types of demand response. While there may be some implementation challenges as well (e.g. whether one should use a mixed integer approach to e.g. model demand response times and frequency) the main challenge is to find appropriate data for demand response.

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[29] http://www.evolvdso.eu/getattachment/6f0142bf-0e66-470c-a724-4a8cbe9c8d5c/Deliverable-1-4.aspx

APPENDIX 1: INPUT TO THE IA MODELLING TEAMS

The data collected as part of this study was used as an input to the Impact Assessments conducted by use of various modelling tools. The aim of the modelling was to quantify the costs and benefits of removing different distortions by implementing various measures and removing barriers, in terms of increased market efficiency.

The consortium has throughout the project worked in close collaboration with the modelling teams from NTUA and Artelys who were commissioned by the European Commission to perform the impact assessment, using the Primes model framework and the METIS model respectively. Our tasks in this collaboration were threefold:

1. For the market distortion identified, provide relevant quantitative or qualitative input data to be used by the modelling teams of E3M Labs and Artelys.
2. Discuss in detail how certain distortions could be modelled. This was in particular concerning distortions where the implementation was not straight forward (e.g. a simple restriction). Here we were in close dialogue in order to understand what the respective models are able to capture and what not.
3. Provide proxies for data that can be used to model distortions in case either data was missing, or in case the distortion could only be modelled indirectly (e.g. by finding data on how balancing responsibility for renewable generation may impact the size of the intraday market).

The discussion involved also close collaboration with parties from the European Commission in order to ensure that the proposed policy measures that were addressing the different distortions were consistent with the model setup and the provided data.

As for the METIS quantification exercise, we had a particularly close dialogue around the following issues:

- Priority dispatch and curtailment – What sources have priority access in markets, and what are the curtailment rules. What are the reasons for curtailment (over-supply versus local grid issues)
- Intraday market coupling and the use of NTC – How are intraday markets coupled, and how are cross border capacities utilized
- Reserve dimensioning, procurement, and operation - How to TSO define the size of the balancing services to be procured, what types of sources are included/excluded, whether there is cross-border provision of reserves, and other relevant market information to balancing services (block-bid structure, symmetric bid, frequency of procurement).

In all cases, we looked into current practices and described the available data and information on these topics. For those countries and data types where information was not available we discussed alternative proxies that could be used in the analysis.

We also supported Artelys in writing the Metis Market Model Configuration document where many of the above mentioned issues are discussed in detail.

APPENDIX 2: LITERATURE SOURCES FOR COUNTRY FACTS

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APPENDIX 3: QUESTIONS TO COUNTRY EXPERTS

Day-Ahead Markets

- Price caps
  - Give an indication on the annual traded volumes on the DAM
  - Is wholesale pricing subject to cap and floor restrictions (max/min prices)? If so, what is the minimum (floor) and maximum (cap) allowed values?
  - What is the basis for cap and floor values? (e.g. Value of Lost Load (VoLL)/how is it calculated?)

- Barriers to participation of certain resources
  - What is the minimum size (MWh) for a bid?
  - Which order types are available on the DA market?
  - Is aggregation of bids (and units) allowed?
  - Is DR allowed to participate?
  - What is the average participation (influence) of DR compared to peak demand?

- Market price impact on RES investments and operation decisions
  - What are the types of implemented RES support schemes (FiT, FiP, certificates, other)?
  - Value (€/MWh) of implemented support schemes
  - Type and value of exemptions RES is entitled to (e.g. lower to none imbalance penalties, other)?
  - Curtailment when prices are negative?

- Criteria for bidding zone delimitation
  - How many bidding zones are covered by the day-ahead market?
  - How are bidding zones determined (e.g. based on structural bottlenecks, geo-political borders, other)?
  - Describe the rules for re-dispatching/internal congestion management
  - Does re-dispatching affect x-border trade?
  - Is re-dispatch optimized or ad-hoc?
  - Is there quantitative data on re-dispatch/internal congestion?
  - What are the indicative re-dispatch volumes?

- Discrimination for dispatch between technologies
  - Are RES or other technologies subject to priority dispatch?
  - Are other technologies subject to exemptions (e.g. priority dispatch, lower imbalance penalties, other)?
  - Are there particular restrictions for certain power producing technologies on the amount of electricity that they can produce on annual (MWh/y) base or during their lifetime (total MWh) or in operating hours (h)? Which technologies and limits?

- Prioritization of curtailment/re-dispatch post wholesale market
  - Which technologies have priority dispatch in connection with re-dispatching?

- Market coupling
  - How is market coupling with neighbouring countries executed (Implicit/explicit auctioning, ATC, FBMC)?
  - How exactly is cross border capacity included in market clearing algorithm?
  - What is the share of IC capacity auctioned in long term auctions?

- ATC allocation along timeframes
  - Is cross-border capacity allocated along market time frames?

- Regional Coordination
  - How are ATC's calculated?
  - Is the ATC calculation transparent?

- Shadow auctions
  - Does the market clearing algorithm has a treshold clearing price (triggering a shadow auction)?
  - If so, is this price transparent/published?
  - If so, what is the value?
  - What is the procedure after bids are adjusted and resubmitted?

- Market power mitigation
  - What is the amount/share of electricity that is traded on the PX versus what is traded through long term contracts?
  - Is market power being monitored in one way or another?
  - Any specific issues with market power?

Intraday markets

- Gate closure
  - Has an intraday market been implemented? If so, is it discrete or continuous?
  - What is the GCT for the implemented market sessions (sittings)?

- Barriers to participation
  - What is the minimum size (MWh) for the bid?
  - Which order types are available?
  - Is aggregation of bids (and units) allowed?
  - Are there special conditions to participate?
  - Is DR allowed to participate?
  - What are the annual traded volumes?
  - What is the ratio of ID volume in relation to DA volume?

- Price caps
  - What is the minimum (floor) and maximum (cap) allowed values?

- Market coupling
  - Is the intraday market coupled with other market(s)? (if yes, list the markets)

- Allocation of IC capacity for X-border IDM trade
  - Is it possible to reallocate IC capacity for x-border IDM trade?
  - How is the cross-border capacity that can be used determined?
  - How is market coupling with neighbouring countries executed?

- Activation of re-dispatch within intraday time-frame
  - At what time does the TSO start re-dispatch?

Balancing markets

- Procurement methods
  - Is there a market base approach for procurement? If yes provide basic info
  - Is there a contract based for procurement? if yes provide info for methods for procurement implemented, eligibility of balancing provides, volumes and values contracted
  - Are any Balancing actions taken from TSO that might affect DA and ID markets, especially as far as the time frame of the markets is concerned? If yes specify.

- In case of a daily operated market for the provision of balancing services:
  - Provide Time schedule/Gate closure times
  - Provide the Price caps on Capacity Offers for balancing services
  - Provide the Price caps on Energy Offers res for balancing services
  - Time granularity of the products (in relation to when balancing actions (""Gate closure"") are taken)

- Product description
  - Are product definitions harmonized with ENTSO's definitions?
  - Capacity required by TSO for each product (up and down)?

- Eligibility criteria
  - Any special provisions or obligations (if any systematic) imposed by TSOs for specific products?
  - Are there any technical, regulatory or economic constraints to participate in the balancing mechanism?
  - Are there any specific Technical characteristics required from Units for ramping services?
  - Who are balance responsible parties?

- Regional dimension
  - Are balancing resources procured at a regional level?
  - If yes, how is the regional procurement organized?
  - Is it possible to reallocate IC capacity to the balancing market?
  - Is there any x-border exchange of balancing services?
  - What is the significance (value, volume) of transactions between TSO's for balancing services?
  - Is the procurement of balancing resources based on a regional assessment of needs?
  - Provide info (frequency, volumes) when balancing services procurement is due to Cross Border activity, and especially on changes of cross border capacities due to technical or other reasons between DA (especially in case of Power Flow Market Coupling) and ID or BM.

- Remuneration questions
  - What are the Prices offered for balancing services by participants (year average, max/min)
  - Basic figures for balancing services (volumes, prices, values)
  - Provide info for the allocation of total income between BS providers
  - Provide info on the Importance of Balancing services income for each type of providers
  - Basic Figures for the imbalance settlement (volumes and prices)

Capacity mechanisms

- What reliability standard is used (metric)?
  - Is cross-border contribution taken into account?
  - Is DSR taken into account?
  - What methodology is used for the capacity adequacy calculation?

- Type of CM and rules for participation
  - What type of CM, if any, is implemented?
  - Is capacity de-rated?
  - What are the rules for de-rating?
  - Is any significant party excluded from participation?
  - What are the rules for participation?
  - How is capacity remunerated?

- Provisions for x-border trade
  - Are there any such provisions?
  - Is X-border participation open to all (generation, interconnectors, load) on equal terms?

- Rules for activation of reserves
  - In what situation is the capacity reserve activated?
  - How are market prices affected?
  - How is the activation price set?

- Are there any criteria to deny decommissioning?

- Do the rules and/or remuneration for denial of decommissioning discriminate between technologies?

- If decommissioning is denied, how is the capacity remunerated?

Hedging opportunities

- Are there any barriers to long-term contracting?

- Indicators of liquidity in financial markets?

G-tariffs

- Locational signals
  - Do G-tariffs contain locational signals?
  - If yes, what is the basis for the locational element?
  - Do G-tariffs discriminate between technologies?
  - Do G-tariffs depend on the grid level?
  - If yes, what is the basis for the difference?

Retail prices

- Are retail prices regulated?

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