Options for the design of European Electricity Markets in 2030

Discussion Paper for Stakeholder Consultation

Publication date: 31 March 2021

European Network of
Transmission System Operators
for Electricity

entsoe

About ENTSO-E

ENTSO-E, the European Network of Transmission System Operators for Electricity, represents 42 electricity transmission system operators (TSOs) from 35 countries across Europe. ENTSO-E was registered in European law in 2009 and given legal mandates since then.

Contents

1 Introduction

1.1 Background and objective of the paper

In recent years, the Third Energy Package, with its related Network Codes and Guidelines, and more recently the Clean Energy Package have paved the way for progress in the transition to a climate neutral electricity system with consumers at its centre. However, more challenges lie ahead to enable the full transition of the European power system, especially in light of the increased ambition of the European climate targets for 2030. Considering the speed and complexity of this transition, the current market design does not appear fully future-proof for 2030 and beyond, at least not in all market timeframes or regarding the specific needs and challenges of all European countries.

Decarbonisation, digitalisation, and greater decentralisation will transform the power system. Anticipating such longer-term challenges, in 2018 ENTSO-E began assessing options for further improvements to the market design in the 2030 horizon and beyond, in particular focusing on the better alignment of market operation to power system operation. In November 2019, ENTSO-E presented at its annual conference a high-level Vision of Market Design and System Operation in 2030. The analysis has since continued and extended its scope to other relevant aspects of market design such as resource adequacy and investment signals.

The current results of our ongoing analysis on 2030 market design, partly anticipated at a public webinar[1] on 12 October are presented in this paper. Our objective is to **trigger an open policy debate on a wide range of possible market design evolutions** – which may be more or less suitable depending on the different European countries – **with all relevant European stakeholders**.

Such a debate should help bring together the different viewpoints and expertise, identifying priority areas for further analysis beneficial for ENTSO-E and TSOs, but ideally for all interested parties. Our ambition is that this stakeholder dialogue, enriched by the technical expertise of TSOs and the neutral role of ENTSO-E, can ultimately inform policymakers so that the findings, the consensus points and different opinions can support their legislative and regulatory choices for shaping future market design in Europe and its individual countries.

To facilitate this open debate, it should be noted that the **possible market design evolutions outlined in this paper** are merely options we have considered in our analysis and **are not intended to represent ENTSO-E positions or TSOs views**.

As concluded in our 2030 Vision Paper **Reconcile Market and Physics**, we believe that a radical market design change in the whole of Europe is neither necessary nor desirable. Nevertheless, further improvements will be necessary – at least in some market time-frames – to make markets fit for purpose in 2030 and beyond. As countries face different challenges and have different policy priorities, such **market design improvements could be designed depending on the specific associated costs and implementation benefits** (economic, social, environmental). Some countries may therefore consider more sophisticated market design solutions or specific features compared to others.

ENTSO-E and TSOs are fully committed to the implementation of the current legislative framework based on the Third Energy Package Network Codes and Guidelines, the Clean Energy Package Regulations and Directives, and national legislation. It is nevertheless our role – as is the role of any stakeholders – to attempt anticipating the future challenges and possible solutions which may require adjustments to the current framework in the coming years.

1 Webinar slides presented by ENTSO-E available at: **https://eepublicdownloads.azureedge.net/webinars/201012_MD%20Webinar_Master%20slides_FINAL_with%20polls.pdf**

1.2 Scope of the paper: key market design challenges

With regards to challenges faced by TSOs, some are already very evident today and linked to some perceived limits of today's target model in dealing with a larger share of renewable energy sources (RES): increasing gap between the market outcomes and the physical reality of the grids; challenges in determining optimal and widely acceptable bidding zone configurations; market parties' accusations of transmission capacity withholding and lack of transparency; increasing loop-flows; significant redispatching and countertrading needs to correct market outcomes; and the limited information available on the power system flexibility. In addition, whereas policymakers and stakeholders put pressure on TSOs to move gate closure times close to real-time, the security and the correct balancing of the electric system require TSOs to have a minimum time margin before energy delivery. Lastly, market rules, products and processes need to be adapted to reflect the changing nature of participants from both demand and supply side.

The rapid evolution of the electricity system, from traditional fossil fuels generation towards low-carbon resources dominated by renewables, also poses challenges to the capability of electricity markets to ensure resource adequacy, especially considering the increasing likelihood of extreme climatic events caused by climate change. As some power plants are decommissioned due to policy requirements or insufficient revenues, it is essential that the market design ensures that sufficient resources (be them conventional generation, renewable generation, demand response or storage) are present in the system at all times, and especially when weather-dependent generation is scarce. Thus, it is essential that electricity markets are designed – and improved taking into account the long-term evolution of the European power system – to deliver effective investment signals and appropriately remunerate the value of adequacy offered by the various resources. If this rapid transformation is not accompanied by fit-for-purpose market design changes, there are concerns that electricity markets may not provide sufficiently effective investment signals to ensure the resource adequacy of the system

The recent electricity shortages in Texas of February 2021 have highlighted the risks that power systems face as well as the severe consequences in case of lack of resource and system adequacy. Regulation and market design, together with system planning and operation, can play a decisive role in addressing increasing challenges posed by the energy transition and climate change. While the recent events in Texas have not been specifically treated in this paper, ENTSO-E will be happy to discuss with stakeholders – including at the 10 June market design workshop – the main takeaways relevant for the European power system.

In addition to the continued development of the grid infrastructure – critical for efficiently accommodating variable and low carbon generation – our analysis shows that several market design solutions exist for Europe as a whole, with various degrees of suitability for different market situations. Some could be integrated as evolutions of the current target market model with minimal implementation efforts, whereas others would require more fundamental changes with longer transition. In any case, further in-depth analysis and discussions with stakeholders will be necessary.

1.3 Stakeholder consultation and follow-up

On 12 October 2020 ENTSO-E organised a stakeholder webinar to begin presenting our market design vision for 2030. Key stakeholder associations participated and contributed to the debate reacting to ENTSO-E views while calling for further discussion on the solutions presented and more in general on 2030 market design.

With this paper, we intend to present our views in more detail and seek open and extensive feedback from stakeholders through general and specific questions. The written feedback from stakeholders will help ENTSO-E understand the level of consensus on the different options, as well as potentially reconsider some of our analysis or priority areas for further analysis in light of the comments received.

The results of the consultation will be made public and discussed in a dedicated workshop on 10 June 2021. Further details on the timing and registrations will be published on ENTSO-E website.

2 Wholesale Markets

Market rules, products, and processes require adaptation to reflect the changing nature of participants from both demand and supply side. Although numerous changes have been already introduced thanks to the implementation of the Network Codes and Guidelines (CACM, EBGL, FCA), and others are in the pipeline following the adoption of the Clean Energy Package, further progress is likely required for 2030 and beyond.

2.1 RES and Consumers participation

The high penetrations of variable RES, demand response and storage lead to a system characterised by more dynamic demand and supply trading. The increasing variability of production and consumption will increase the importance of trading close to real-time.

2.1.1 Wholesale market products

Wholesale market products and processes are already evolving to facilitate the access of emerging resources such as RES, demand response and storage, reflecting the smaller size and more variable infeed/production compared to large conventional generators. The implementation of the Network Codes/Guidelines and the Clean Energy Package provisions underpins this ongoing evolution.

For instance, finer time granularity products (i. e. 15 mins Imbalance Settlement Periods and Market Time Unit) incentivise market access of new resources (e. g. storage) by allowing the value of their flexibility to be captured better. Although this process is necessary, it also requires some time and costs to be implemented, particularly for cross-border exchanges. Possible future evolutions to even finer time granularity products (e. g., 5 mins) will require careful evaluation from a cost-benefit perspective.

Across coupled day-ahead (DA) and intraday (ID) markets, smaller minimum bid size products (e. g., max 500 KW) are being introduced to facilitate market access of smaller and distributed energy resources (DER). As per balancing markets, 1 MW is already the minimum bid size for standard balancing products (i. e., RR, mFRR and aFRR). Removing market barriers to aggregators will also support this process. Although digitalisation is making this transition easier, further reduction of minimum bid sizes leads to a trade-off between the increasing complexity of markets and operations and market access for small players.

Questions

1. How could European Day-Ahead and Intraday markets be improved to further facilitate market access of RES and Distributed Energy Resources in 2030?

2. Are there any best practices which could be used as an example?

2.1.2 RES participation in balancing markets

With the increasing share of RES, it becomes increasingly important that RES also provide system balancing services. One of the main challenges is to integrate RES in balancing markets. Participation of RES in balancing markets is already allowed in many countries as established both in the Electricity Balancing Guideline and in the Electricity Regulation. Nonetheless, the effective participation of RES in these services has still not reached its full potential.

Balancing markets should be as "open" as technically possible to all participants, facilitating access to emerging technologies and players such as RES. For this purpose, explicit technical barriers to RES participation in short-term markets – such as specific pre-qualification rules or disproportionate IT requirements – should be removed. In addition to technical barriers, RES participation could also be impeded by regulatory ones or by the lack of economic incentives, depending on the type and/or design of specific support mechanisms. In this sense, each type of support scheme (e. g., FIT, FIP or investment supports) incentivises different behaviours.

Feed-in-premiums (FIP) support schemes based on energy infeed induce distortions in the balancing merit order as RES producers factor in the loss of premium when submitting downward offers. To address these shortcomings, RES support schemes should be designed so that they do not (implicitly or explicitly) prevent RES producers from offering their flexibilities on balancing markets. In this regard, existing support schemes may need to be reviewed – in close cooperation with RES market parties – to satisfy this objective.

One possibility would be to also pay the premium when RES gets activated for negative balancing energy (similar to the compensation frequently paid for RES curtailment). Another suitable solution would be to pay the premium not for a fixed period but for a fixed number of full-load hours. In this case, the premium is not lost when a RES unit is activated for down-regulation but can be regained later. Another possibility is represented by capacity-based support schemes (also known as "investment support" schemes), which can minimise distortions in the balancing markets as market players will be incentivised to bid their marginal cost, and will not lose any support associated with the reduced energy when being down-regulated.

Questions

3. What do you consider to be the main barriers for the participation of RES in balancing markets?

4. Which kind of support scheme has the least distortive effect on the participation of RES in balancing markets?

5. What do you consider as best practice to the ensure effective provision of voltage control and other non-frequency Ancillary Services (AS) by RES?

2.1.3 RES Supports and Negative Prices

Negative prices are a sign of the inflexibility of the energy system as they occur when not all electricity infeed can be matched by demand or exports, and it is still more profitable for some generators to continue generating at negative wholesale prices than to disconnect. A certain degree of system inflexibility is, however, inevitable and even efficient. Therefore, it is important that based on a free price formation principle, such price signals are allowed to occur to send incentives to market participants which reflect the current system status. Although it may seem odd that producers would pay for the electricity they produce, there are reasons behind this. The two main origins are:

- Considerable start/stop costs of some power plants; and

- If assets receive other remuneration outside the wholesale market, i. e., the CHPs that produce steam, assets which provide system services to the system operator, must-run, or assets that receive subsidies for their electricity infeed (such as RES) via certain types of support schemes.

While negative prices do not constitute an adequacy challenge in itself, their indirect effect can cause issues from a system operation perspective. If, in fact, a large number of generation capacity disconnects in a short period of time because of negative prices, this leads to significant challenges, such as ramping, as we are already seeing in some countries. In times of negative prices, assets like wind farms or PV stop producing electricity if a market premium is not being paid. These quick in-feed changes result not only in challenges for operating margin but also in significant deterministic frequency deviations[2] and local/zonal voltage issues.

Question

6. How could market design mitigate the side effects of the interaction of negative prices and RES supported technologies?

2 For more information about deterministic frequency deviations, see ENTSO-E technical report (2019): **https://eepublicdownloads.entsoe.eu/clean-documents/news/2019/190522_SOC_TOP_11.6_Task%20Force%20Significant%20Frequency%20Deviations_External%20Report.pdf**

2.1.4 Consumers become active prosumers

One of the key goals of current European energy policies is to further open electricity markets to consumers. This includes small active users (prosumers) who are able to buy and sell energy directly or through aggregators, as well as local energy communities and renewable energy communities.

Final customers must, in fact, be entitled to operate in the electricity market as active customers either directly or through aggregation[3], as well as being able to sell self-generated electricity and participate in flexibility and energy efficiency schemes. For this purpose, Member States shall complete an ambitious program of deployment of advanced metering infrastructure. When complemented with individual meter allocation, this will allow demand resources to respond to time-dependent market price signals.

As regards storage assets, it is likely that the costs of battery storage will significantly decrease[4] in the coming decade mainly due to the massive production of batteries for electric vehicles (EVs), as well as dedicated R&D interests in storage technologies. The increasing penetration of batteries within the energy system will positively contribute to resource adequacy during short-term scarcity events. However, there is a limit to the potential penetration of batteries within the energy system, as decreasing technology cost is offset by increasing the "cannibalisation effect": the more batteries are built in the system, the lower the revenues that batteries can access by storing energy during low-priced periods and generating in situations of scarcity when electricity prices are high. In addition, for more extended scarcity events, batteries will probably not become a viable alternative in the foreseeable future.

Incentives for demand side response

Demand side response (DSR) is one of the major pillars for the future power market, as is clear from the EU Clean Energy Package. However, the full potential of DSR has not been realised: small and residential DSR could offer opportunities in the future, and some forms of incentives may be required to boost DSR:

- DSR tenders on a national level; or
- Mandatory provision of a certain percentage of DSR by suppliers.

Apart from new measures or targeted incentives for DSR, it is essential to remove any potential barrier to market access. The following barriers were included in the EG3 Report[5]:

- Lack of standardisation of market rules and energy products;
- Lack of standardisation or at least interoperability of hardware (i. e. smart meters, charging stations etc.);
- Lack of a framework for DSR providers (i. e. aspects such as Allocation of energy volumes and balance responsibility, Baselining methodology or Remuneration for transfer of energy);
- Data access and data sharing; and
- Pre-qualification processes that are insufficiently user-friendly, proportionate or transparent.

ENTSO-E has analysed which regulatory requirements for the integration of distributed flexibilities in balancing and congestion management could be introduced – on top of the existing framework – and which should be further developed to promote DSR in the near future:

- The possibility to access and use sub-meter data for the verification of activation and financial settlement of flexibility services (and ensuring their certification) for example as part of the new implementing act on data interoperability or by amendment of existing network code/guideline. The rationale is the use of sub-meter data for the easier participation of demand-response units.
- Discussion with stakeholders regarding possible baseline methodologies for the provision of balancing and congestion management services by demand-side responsive units and the provision of balancing services by variable renewables units.
- EU framework to provide a standardised pre-qualification procedure and related TSO-DSO cooperation for the provision of balancing services.

---

3 EC, Article 15 of the Directive (EU) 2019/944

4 See for instance Bloomberg New Energy Outlook 2020 or IRENA report on Electricity Storage **https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf**

5 **https://ec.europa.eu/energy/sites/ener/files/documents/eg3_final_report_demand_side_flexiblity_2019.04.15.pdf**

Other market barriers are mentioned in other public papers and industry reports on the status of European DR development, such as the recent SmartEn monitoring report[6]:

- Limited use of dynamic price retail contracts;
- Lack of time differentiated network tariffs; and
- Free access to end-customer data by eligible parties (based on consumer consent).

Questions

7. What do you consider to be the key market design barriers limiting the uptake of DSR?
8. What do you consider to be the best practices for the facilitation of demand side response?

2.2 Day-ahead, Intraday and Forward Markets

The day-ahead market optimisation plays an important role as it creates a forecasted economic dispatch while performing congestion management by allocating scarce transmission resources between bidding zones. In this regard, an essential characteristic of many of the European day-ahead markets is that market participants can bid in on a portfolio basis and thus optimise their positions in a zone by self-dispatch. Intraday markets complement and adjust the initial cross-zonal schedule and enable market parties to minimise deviations between schedules and final energy injections and withdrawals.

The ongoing transformation of the power system, in particular increasing variable RES, electrification and active consumers will require stepwise improvements of the energy markets to efficiently meet the future challenges of the energy transition. With the increasing penetration of weather-dependent RES and demand response, the importance of intraday and balancing markets will increase as day-ahead markets will be – in relative terms – less able to capture close to real-time outcomes and sudden changes in market conditions.

A number of market design improvements can be imagined to better adapt to the future generation mix and power system. One such example is moving to shorter resolution products, jointly managed with larger resolution products, an increase of the number of intraday auctions; and a possible review of gate closure times (compatibly with operational procedures), all paired with increasing volumes traded shortly before real-time.

2.2.1 More Intraday Implicit Auctions

The rationale for more frequent intraday auctions could be argued for a number of reasons:

- **Efficient allocation and pricing of cross-zonal transmission capacity:** Allocation of cross-zonal transmission capacity in an auction maximises social welfare by awarding transmission capacity to those who value it the most, as opposed to continuous trading which is a first-come-first-served mechanism. This is particularly relevant to capture liquidity associated with new information on cross-zonal capacity being made available.
- **Setting a reference price for derivative products:** Gathering the liquidity in an auction increases the importance of this market which can be used as a reference price for derivative products to hedge basic risk.
- **Potentially better in unlocking all flexibility by solving intertemporal dependencies:** Depending on the auction mechanism, it is possible that energy can be traded for many hours, bids can be linked in time, and the efficient matching of offer and demand can be done for each market time unit.
- **Incentives for competitive and easier bidding strategy:** Following a "pay as cleared" mechanism the market actors are incentivised to bid along their marginal cost knowing that they can benefit from the spread between the clearing price and their bid unless it is at the clearing point.
- **Incentivise liquidity and market participation:** Auctions generally allow more active participation from smaller market participants, especially as bigger market participants can use their trading department 24/7 to take advantage of the continuous trading possibilities which emerge at unpredictable times.
- **Ensuring secure operation of the market:** In continuous markets, algorithmic trading and the speed of trading determine who can benefit from the margins. Consequently, enormous volumes of bids are placed that risk creating backlogs in execution and could endanger the secure operation of the markets.

6 https://smarten.eu/wp-content/uploads/2020/11/FINAL_smartEn-EMD-implementation-monitoring-report.pdf

However, continuous trading provides market participants and mainly variable renewable energy sources, DSR and storage with more flexibility to adapt on an ongoing basis their schedules. Intraday Auctions (IDAs) are positive for a number of reasons, but they introduce a certain degree of rigidity in the scheduling process of resources (such as RES or storage) as they do not allow it to be to continuously adjusted (i. e., before the following auction), as is the case with continuous trading.

For each new auction, an additional step of calculating the remaining transmission capacities has to be implemented. As the capacity calculation takes a certain amount of time, it needs to be carefully assessed whether it is possible to embed a given number of additional implicit intraday auctions into the operational processes of TSOs.

Lastly, with the possible increase of intraday auctions, the role of continuous trading in the European cross-border market could be reconsidered. Although on the one hand it may become of limited added value if intraday auctions become very frequent, on the other hand it could still be an additional option for market parties to take advantage of potential opportunities between auctions. Ultimately, the market will most likely reveal if there is continued appetite for such an option.

Questions

9. Do you see benefits in increasing the number of intraday auctions?
10. If so, what would be an adequate number of auctions per day?
11. Would you still see a role for cross-zonal intraday continuous trading if such adequate number of Intraday auctions would be implemented?

2.2.2 Combining day-Ahead and Intraday Auctions

Once sufficient cross zonal Intraday Auctions are in place the day-ahead auctions could be integrated into the design of the intraday markets, and act as an opening auction in a series or moving window of intraday auctions. At the day-ahead auction (D-1), where market participants can place bids for the entire next day (D) the cross-zonal transmission capacity is allocated. This auction is followed by a series of subsequent auctions (e. g., every hour) where energy is traded for every remaining market time unit (e. g., quarter-hour) of the day (D) wile recalculations of Available Cross zonal transmission capacity closer to real-time are performed to ensure an efficient outcome. Furthermore, more frequent intraday auctions could also replace the current complex and sub-optimal market coupling fall-back procedures.

Questions

12. What potential benefits or drawbacks do you foresee in combining day-ahead and intraday auctions?
13. Would you recommend any alternative solution which could achieve similar objectives?

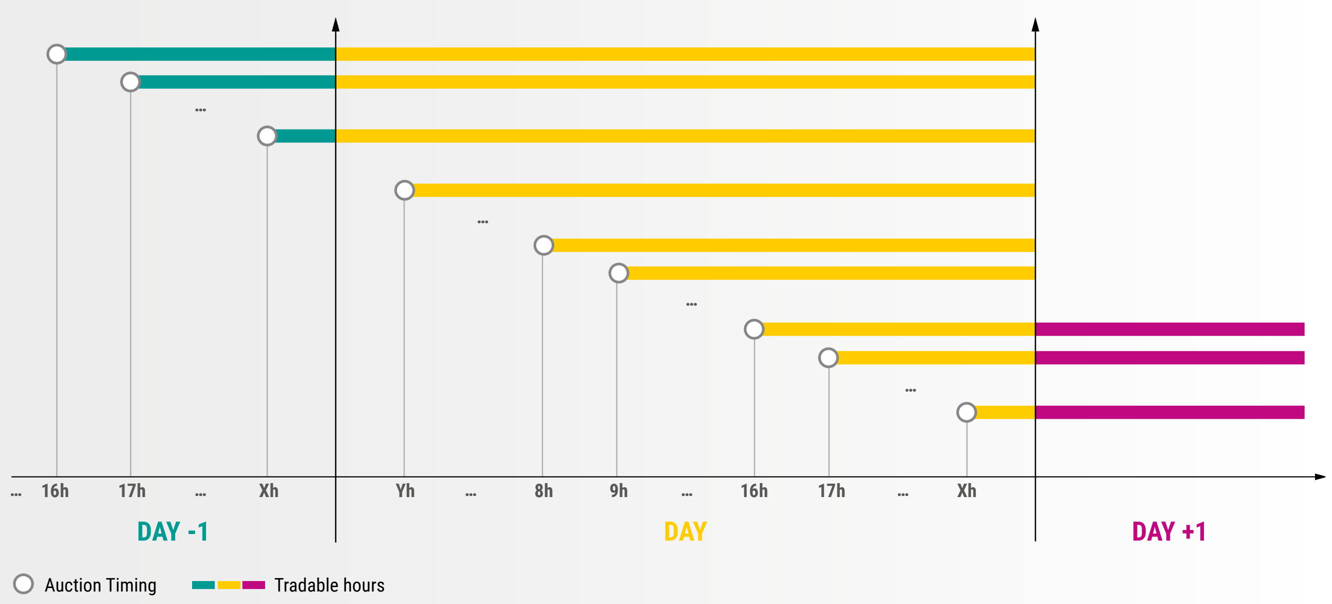

Figure 1: Illustration of a possible combination between day-ahead and intraday auction.

2.2.3 Evolution of Markets for Forward Transmission capacity

Well-functioning and liquid forward markets are an essential element of electricity markets, allowing market parties to hedge their price and volume risks. The long-term visibility of costs and revenues is essential for facilitating investments. As cross-border transactions increase with market integration, market parties also need to be able to hedge – where relevant, via long term transmission rights – the risk of price differences across bidding zones.

European forward electricity markets have reached a good level of liquidity, with a plurality of products traded, both through exchanges and over-the-counter (OTC). However, forward markets for cross-border transmission capacity are relatively less mature with a limited number of "standard" products.

A number of evolutions could be imagined:

- Although currently yearly and monthly products are mostly available, market parties may require more granular and specific products such as multi-yearly products, peak/off-peak, week/weekend, etc. The possible introduction of block bids should also be considered[7].
- An organised secondary market could allow market parties to hedge their position efficiently and on a continuous basis. However, the impact of the requirements stemming from financial regulation should be properly assessed in this case.
- Allocation of Long-Term Capacity could be done on Flow-Based parameters (where relevant) and per bidding zone border. LT Capacity auctioned per bidding zone border would be based on maximising economic surplus. However, several questions remain as hedging possibilities for market parties, transparency, re-allocation of revenues due to resales, new congestion income distribution methodology, and level of capacity given by FB domain.

Questions

14. How could markets for forward transmission capacity be improved to support the energy transition?

15. Do you see value in developing new durations of long-term transmission capacity products mirroring products for forward electricity trading?

16. Do you see other means to improve the forward markets and hedging possibilities besides long-term transmission rights?

7 See also **https://consultations.entsoe.eu/markets/blockbids_new_approach_lttrs/consult_view/**

2.3 Balancing Markets

Higher RES and storage penetration, as well as new technologies, and the more active role of consumers and emerging prosumers, increase the importance of further developing balancing markets. The first step of this process is the implementation of EBGL and European balancing platforms, which aims to increase the efficiency of balancing. However, in the long-term, more improvements in balancing timeframe may be beneficial. Below we consider several specific solutions to enhance and further develop the balancing market.

2.3.1 Co-optimisation of energy and balancing capacity

One of the potential improvements related to balancing capacity markets is the co-optimisation of energy, and balancing capacity in the day-ahead market. Clearing all products delivered and consumed by generation and load units within one optimised process, performed in the reserves procurement timeframe, could lead to more efficient resource usage than sequential markets of aFRR, mFRR, RR and the Day-Ahead market.

In a co-optimised market clearing, there is no generation/load capacity blocked upfront, i. e. TSOs do not procure balancing capacity ahead of the day-ahead market. These are procured together with energy in a liquid wholesale market, meaning that no generation/load capacity is withdrawn before the wholesale market. This common market for balancing capacity and energy should allocate products delivered by a single set of physical resources in an optimal manner, considering all interdependencies. It should also improve the usage of cross-zonal transmission capacity avoiding sub-optimal reservation and allocate cross-zonal capacity to the products that give most welfare gain, as foreseen in Art. 38 – 42 of Electricity Balancing Regulation GL, which introduces at Art. 40 the co-optimisation as one of the cross-zonal capacity allocation methodologies for the balancing capacity timeframe.

However, a number of implementation challenges and complexities lie ahead. These are part of the official implementation impact assessment in which TSOs join with NEMOs to explore the remaining conceptual and processual challenges. Among others these are the impact of co-optimisation on the performance of EUPHEMIA, the impact on computational timings of optimising several markets, and the challenges of flow-based as the allocation of balancing capacity does not necessarily results in an actual flow of balancing energy. Lastly, the benefits of co-optimisation over other alternative methods of cross-zonal capacity allocation for balancing capacity remain to be demonstrated.

Questions

17. Which potential benefits or drawbacks do you foresee with the co-optimisation of energy and balancing capacity?

18. Would you recommend any other solution which could achieve similar objectives?

19. Do you think that the implementation of co-optimisation or other market features could increase market complexity to a level which may be detrimental for the entrance of new players?

2.3.2 Congestion management and balancing

The importance of congestion management in both transmission and distribution networks is also expected to increase in the coming years. Firstly, this is to deal with the new connections of variable RES generators – more dispersed and/or distant from load -, but also to manage increasing complexity due to more cross-border flows as week as the more dynamic load patterns due to emerging demand response and distributed energy resources. Until now, congestions occurring in the transmission grid have been rather stable and predictable, so they could be solved in longer timeframes using a limited number of resources and static mechanisms. However, the future market will require a much more dynamic use of the transmission and distribution grid and more actions taken in shorter timeframes, both by TSOs and DSOs to integrate energy from volatile and distributed resources to distributed load while ensuring stable grids and adequate capacities. As such, more congestion management actions will need to happen closer to real-time. This will have direct impacts on the task of some TSOs which activate balancing bids as part of the congestion management to balance energy infeed and offtake.

To consider such expected developments, a more efficient and fit-for-purpose congestion management approach for 2030 and beyond should generally entail:

- More dynamic and shorter-term procurement, taking the benefits of new resources and market actors such as storage, distributed generation, load (aggregated or directly participating);
- More market-based procurement as a general principle, provided there are sufficient providers to establish competitive and liquid markets without inefficiencies due to market power;
- More cross-border coordination among TSOs;
- Closer coordination, and possibly integration, of balancing and congestion management, to improve system efficiency and increase pooling the of resources; and
- Close coordination between TSOs and DSOs for the use of flexibility from distributed resources and to monitor the impact of activations on respective grids.

Questions

20. How can TSO procurement of balancing services evolve to be a better fit for the new power system of 2030?

21. 21. Do you have concrete examples of best practices in the procurement of balancing services?

2.3.3 Further evolutions complementing balancing energy markets

In the electricity system of the future, with massive renewable generation, consumers becoming prosumers with PV, electric vehicles and decentralised storage, market actors will have an ever-increasing need to trade electricity close to real-time.

The accuracy of RES generation forecasts improves significantly when it is sufficiently close to real-time, and the participation of flexible demand (including storage) is easier when it is committed sufficiently close to real-time rather than a day in advance.

An additional feature which could be considered a complement of balancing energy markets – for systems with limited internal congestions and reactive balancing approach – is the further development of "real time markets" close to the energy delivery. This would enable all actors with the specified technical capabilities to submit their bids and demands close to real-time (e. g., 15 or 5 minutes before) to the relevant System Operator to optimise their positions or to minimise imbalances. These bids would then be cleared at marginal price of the balancing energy[8] to achieve the highest surplus. This feature is less suitable in bidding zones with internal congestion and/or proactive balancing approaches, as there would be no time left for solving congestions and balancing the system. Therefore, for such systems, the integration of congestion management in the balancing energy market would be required. The possibilities of congestion management integration in the balancing energy market may vary, as described in **Section 3**.

This potential complement of balancing energy markets may also be enhanced by managing different products (RR, aFRR, mFRR) in one integrated process. This could, in turn, increase liquidity and economic surplus, while decreasing the risk related to splitting capacity between different markets and products.

Questions

22. For system with limited congestions and reactive balancing approaches, would you foresee any benefits to implementing real-time markets managed by the relevant TSO?

23. Are there any other Balancing Markets enhancement which you would recommend?

8 This is the price received when using counter-activations.

2.4 Market Coupling Algorithms

Achieving one of the largest electricity markets in the world is a challenging task that stresses optimisation procedures and tools such as Euphemia. The prioritisation may be required between complexities of products, prices calculation, repeatability, calculation time and spatial-temporal resolution to achieve power markets evolutions, such as the 15 min Day-ahead and Intraday coupling or the Flow-Based extension to CORE.

2.4.1 Product simplification

To fulfil the diversity of the market parties' needs, many different products are proposed by Power Exchanges (e. g., regular blocks, profile blocks, exclusive blocks, linked blocs, flexible hourly block, Minimum Income Order, Load Gradient Orders, PUN Merit orders, etc.). Some products are widely used, such as regular block orders, which have seen their numbers increasing in the past few years, whereas others are used less. The multiplicity of products makes it possible to incorporate many of the constraints of assets in the market coupling but increases the computation burden of the algorithm such as Euphemia. Under some conditions, this cost of computation could jeopardise ambitious evolutions of power markets such as a generalisation of 15-min products for Day-Ahead and IntraDay auctions, Flow-Based extension to CORE, a reduction of minimum bid sizes, etc. These evolutions could create more social welfare than the capacity for market participants to use all of the available products today in order to reflect their constraints. Under these assumptions, the question of a reduction of the currently available products to ease other power market evolutions can be raised.

Questions

24. Would you support the simplification of products traded in the DA and ID auctions to speed up the implementation of ongoing and future market evolutions?

25. If yes, which DA and ID market evolution would you consider to be a priority and which specific products could be discarded?

2.4.2 Alternative pricing methods

The current pricing methodology used by the European market coupling algorithm is called "uniform" and couples the determination of the prices and the determination of the volumes to clear. This method minimises the number of paradoxically accepted/rejected orders and ensures a single price per bidding zone; however, it impacts the computation performances compared to other solutions. Alternative pricing algorithms could decouple the resolution of prices and volumes. These kinds of solutions make it possible to sharply reduce the optimisation time and increase the scalability of the algorithm at the cost of the introduction of side-payments for some participants. These side-payments would be necessary to compensate paradoxically-accepted orders, i. e. bids orders (or ask) cleared but with a clearing price below (above) the proposed bid price. As an example, those side-payments could be covered by the surplus of in-the-money accepted orders. Those alternative pricing methods are promising but still at the research level and could have consequences on the EU regulation[9] and price signal depending on the level of the side-payments.

Questions

26. Which potential benefits or drawbacks do you see with the alternative pricing methodologies described above?

27. Would you recommend any other solution to improve the performance of DA and ID coupling algorithms?

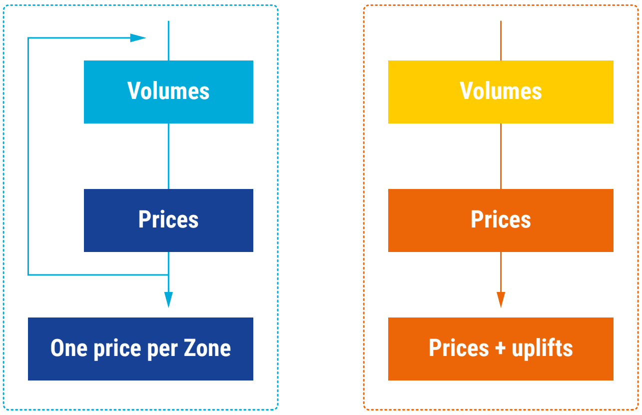

Figure 2: Alternative pricing methodology with a decoupling of prices and volumes

9 Articles 38 and 39 of CACM refer to the "single clearing price".

2.4.3 Adapt the optimisation procedure

The robustness and reliability of the algorithm and related optimisation and clearing processes are essential features for both market parties and TSOs. To address the constraints of the optimisation, while reducing the risk of incidents such as de-couplings, a number of solutions could be imagined and explored.

One of the solutions is to adapt the resolution time to the size of the social welfare optimisation problem. The market coupling process currently allows a fixed 12 minutes resolution time for Euphemia and may be extended in accordance with power markets evolutions. An extension of the computation time should carefully investigate the cost of internal procedures adaptation of the market parties. Another solution could be to maintain an hourly day-ahead auction followed by a close first 15 min intraday auctions. The idea is to split the problem in two. The first auction deals with most of the volume and less hourly orders and the second one deals with the details but with more 15-min orders.

Questions

28. Which potential benefits or drawbacks do you foresee by allowing more time for the algorithm optimisation?

29. Would you be in favour of keeping an hourly auction in day-ahead followed by 15 min intraday auctions?

30. Would you recommend any other solution to adapt market coupling procedures?

3 Congestion Management & Spatial Granularity

All electricity markets have in common their ability to bring together supply and demand for electricity to be delivered at a certain point in time at a specific location. The point in time varies from years to months to days. Finally, it ends up in real-time and the time unit for which unbalanced positions are settled. The location can differ from very large areas to very specific locational points (so-called "spatial granularity").

The point in time of effective delivery is the moment when markets meet physics or where market outcome meet the boundaries of what can physically be realised. The key responsibility of the TSOs is to maintain a secure system operation, in particular by ensuring that the physical limitations of the electricity grid are not exceeded. This task can be performed in an economically efficient manner only if electricity trading is subject to certain constraints.

Therefore, an efficient European market design provides market participants sufficient trading opportunities on the one hand, while leaving TSOs enough flexibility to ensure a secure operation of the system on the other. This chapter elaborates on different market design options with respect to how different models consider grid boundaries when performing their economic dispatch of available resources.

3.1 Zonal

The improved Zonal model builds further upon the current European market design, structured around bidding zones as the locational market-component. All energy trades (from forward markets until the balancing timeframe), through organised markets or bilateral contracts, materialise in delivering energy for a specific time in a specified zone. The day-ahead markets play an important role by creating a forecasted economic dispatch while performing congestion management on a zonal level by allocating scarce transmission resources, in particular, between bidding zones. An important characteristic is that market participants can bid on a portfolio basis and optimise their positions in a bidding zone by self-dispatch. Intraday markets and balancing markets complement and alter the initial cross-zonal dispatch and enable market parties to obtain balanced portfolios in real-time.

The core of the improved zonal model is the adequate delimitation of bidding zones. This implies that bidding zones are to be constructed around areas without major congestion (both structural and material[10]) in the zone. Further possibilities to improve the current zonal model are described in **section 2**.

In a zonal design, market participants benefit from few restrictive trading opportunities, high market liquidity and the opportunity to bid on a portfolio basis. Furthermore, the improved zonal concept allows efficient use of topological actions and enables the establishment of models for aggregating consumers and small-scale generation. However, besides the challenge of implementing a well-defined bidding zone configuration, the zonal design presents some open issues, including the so called inc-dec gaming opportunities as well as marked-based locational price signals being limited to bidding zones[11]. In general, given a well-defined bidding zone configuration, the zonal model represents a suitable European market design option for the future.

Questions

31. Do you think the zonal market model including the planned evolutions of the Clean Energy Package is suitable for the 2030 power system?

32. What is the most important feature of the current zonal market design that must be adapted to make it future proof?

10 Structural refers to the occurrence of congestions over time and material refers to the economic impact, or changes in economic surplus

11 In a zonal design, all market participants within one bidding zone see the same price signal, regardless of their location within the bidding zone. If there is congestion within a bidding zone, their reaction on the price may be infeasible with the system requirements, requiring TSO countermeasures to relieve the congestion, which in turn may lead to an increase in system costs.

3.2 Advanced Zonal

Advanced zonal gathers evolutions that can be implemented without significant technical or regulatory transformation with the aim of increasing the social welfare created by power markets.

3.2.1 PST & HVDC in the market coupling

Phase Shifting Transformer (PST) and High Voltage Direct Current lines (HVDC) are types of network equipment which provide flexibilities to the network thanks to the capacity to control the power flows crossing them and, consequently, all the flows on the grid. This makes them extremely valuable for managing transmission capacities at very low variable costs compared to other options such as redispatching. The integration of increasing amounts of these types of equipment in the European power system, such as cross-border projects like ALEGrO or future internal German HVDC corridors, opens new opportunities for more intense coordination between TSOs and cross-border capacity management. Today, a fixed share of PST setpoints is coordinated across TSOs during the capacity calculation phase taking place two days before the real-time and HVDC set points are optimised during the capacity allocation phase.

As PST and internal/cross-borders HVDC can be roughly modelled by linear equations, they could be incorporated in the Flow-Based methodology quite easily and enhance European power exchanges. To ensure that TSOs have sufficient flexibility for maintaining a secure system operation in real-time (i. e., to deal with forecast errors and issues not addressed in the market, such as voltage constraints or internal grid elements), a fixed share of capacity/tap positions (e. g., 2/3 as today for PSTs) needs to be reserved for operational security. Some studies show (ref to ELIA paper) significant market benefits at the 2030 horizon with planned and current assets. Although the cost of the solution seems minimal compared to the benefits, it still requires regulatory, technical and IT implementation.

Question

33. Which potential benefits or drawbacks do you foresee with introduction of the PST and cross-border/internal HVDC in the allocation phase of transmission capacities alongside the market coupling?

3.2.2 Topological flexibilities in the market coupling

Topological actions are network reconfigurations (i. e., line-switching or bus splitting) operated by Transmission or Distribution System Operator in order to control active power flow, voltage management, outage operations etc. They use the meshed nature of the power network. Those operations are strong levers for transmission capacity management and, thanks to their almost zero variable cost, can result in significant economic benefits for the community, as evaluated by (Hedman, Oren, & O'Neill, 2011)[12]. Unfortunately, those actions cannot be easily modelled in the optimisation algorithm because of their discrete nature. They also cannot be directly integrated into the market coupling as opposed to PST and HVDC. Today, they are optimised by TSO through coordination during the capacity calculation phase around a single forecasted base case. However, it appears possible to offer several rather than only one Flow-Based domain to the market transmission allocation phase and let the optimisation identify the best solution. Each of these domains reflects a coherent topological configuration prepared by the TSO. This solution makes it possible to deal with the uncertainty of the base case between the capacity calculation phase in D-2 and the allocation phase in D-1.

Question

34. Which potential benefits or drawbacks do you foresee with the introduction of several Flow-Based domains in the allocation phase of transmission capacities?

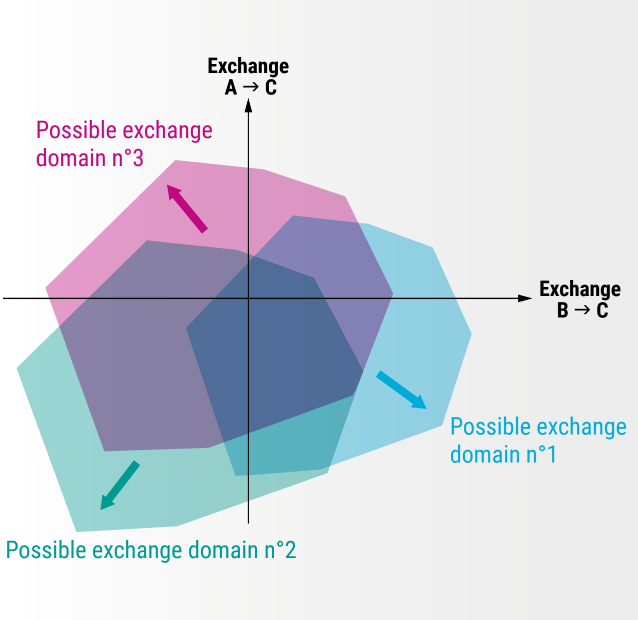

Figure 3: Illustration of several Flow-Based domains offered to the market coupling.

3.3 Dispatch Hubs

A way of improving the market outcome is to integrate additional degrees of freedom into the market coupling algorithm. The starting point is the current target model of Zonal Flow-Based market coupling, including the optimisation of PSTs & HVDCs in the market.

Dispatch Hubs behave like very small bidding zones. Redispatch potential (i. e., of the congestion relevant assets) is identified and placed in separate bidding zones (i. e., dispatch hubs) within an existing bidding zone. Separate market bids are provided for each individual Dispatch Hub. The welfare optimisation function will select costly remedial actions (e. g., redispatch) if these generate net welfare (i. e., more cross zonal trade).

The impact of a change in the net position of a Dispatch Hub on each CNEC is calculated and included in the power transfer distribution factor (PTDF) matrix. A change in net position in a Dispatch Hub impacts the network constraints in the same way as the other variables represented by the columns of the PTDF matrix. This network impact is taken into account by the market algorithm to define the net position and price within the Dispatch Hub. The model creates additional bidding zones in the capacity allocation that consist of congestion-relevant assets. This will still result in one clearing price for the whole bidding zone, whereas Dispatch hubs will have their own price.

Two distinct variants of Dispatch Hubs can be considered. Dispatch Hubs can contain “redispatch potential” bids or “market” bids. The main difference between both methods is whether Dispatch Hubs contain physical assets (e. g. conventional generation) or the redispatch potential of those assets. The mechanics for optimising Dispatch Hubs in the market are similar for both methods.

In the redispatch potential bid variant, a Dispatch Hub represents the redispatch potential, at a certain volume and a certain price, introduced by the TSO to be available at a specific location in the grid (sell or buy bids). Before the market clearing, TSOs submit “Dispatch Hub bids”, as well as

12 Optimal transmission switching: economic efficiency and market implications, Kory W. Hedman, Shmuel S. Oren ·Richard P. O’Neill, 2011, DOI 10.1007/s11149-011-9158-z

data on the impact of the Dispatch Hubs on the grid elements (an extra column in the PTDF matrix). These bids are then included in the market clearing in the same manner as other bids. If the market clearing selects "Dispatch Hub bids", the TSO must activate the underlying redispatch potential after the market clearing. This approach would allow for a wait and see approach, as TSOs could further wait and see whether the redispatch potential must be activated. Such an approach could be interesting in case of redispatch potential of renewables, meaning that the TSO could wait until a later moment on the need for RES curtailment. In the redispatch potential bids model, the market first settles the selected redispatch potential with the TSO. Subsequently, the TSO settles the called upon redispatch with the market parties.

In the market bids variant of Dispatch Hubs, market parties must submit separate bids for resources included in the Dispatch Hubs (e. g. conventional generation units). In this case, TSOs must submit the relevant information of the Dispatch Hub for the PTDF matrix to the market. The market clearing will then directly optimise the resources included in the Dispatch Hubs (instead of selecting redispatch potential for activation.

The use of Dispatch Hubs offers the opportunity to organize an efficient trade-off between the costs incurred by the redispatching to guarantee a certain level of cross border capacity and the additional market welfare so created. In this regard, it would integrate part of the redispatching costs into the clearing prices of the day ahead market and henceforth reflect the merit order effect of redispatching onto the day ahead price level (as opposed to a scheme where redispatching is separated from the market clearing) .

Questions

35. Do you see the Dispatch hubs model as a promising option to be further analysed in the future? If so, which variant: Redispatch potential bids or market bids appears the most promising?

36. Do you foresee any challenge in the implementation/operation of the model?

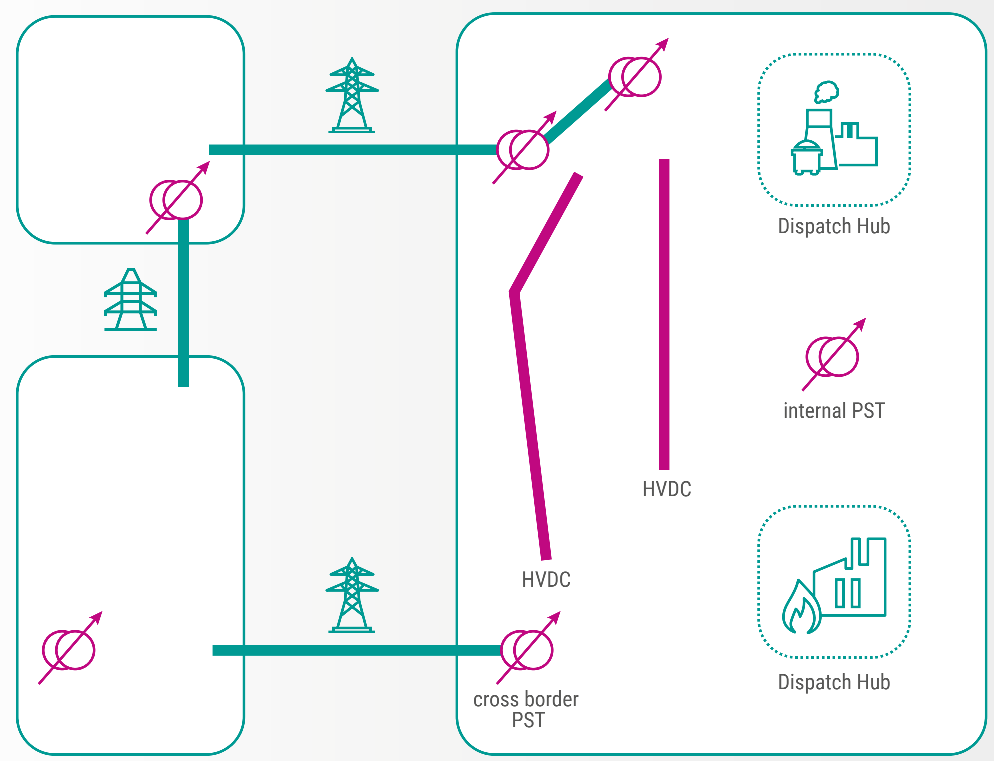

Figure 4: Optimising PSTs and HVDCs and adding Dispatch Hubs

3.4 Location Based Balancing

As stated in **Section 2.3.2**, the future market will require a much more dynamic use of the grid and more actions taken in shorter timeframes to integrate energy from volatile and distributed resources to distributed load. Among others, this implies the closer coordination, and possibly integration, of balancing and congestion management, to improve system efficiency and increase the pooling of resources. Arguably, a market-clearing model that internalises all relevant grid constraints has the most advantages close to real-time because at this stage it is difficult to correct actions that violate the security constraints of the system. For example, after receiving the activation orders from the European balancing platform, the TSO should forward these to the balancing service providers (BSPs) within 30 seconds, which leaves virtually no time for corrective action. Although TSOs are allowed to declare bids unavailable, it is complex to perform ex-ante filtering depending on the congestion they may cause. Therefore, countries with significant intra-zonal congestion need to allow for ample "slack" in their internal flows to avoid violation of constraints in a purely zonal balancing model.

The European zonal market design could alternatively include a more locational oriented balancing market, as an alternative to the planned zonal balancing platforms. Such an approach could be used by countries with material congestions within their bidding zone(s) in co-existence with other countries using the present model (cf. **Section 3.6**), or possibly even on a European scale.

To take into account intra-zonal grid constraints in the balancing phase two central elements are required:

- Inclusion of the detailed grid in the Activation Optimisation Function (AOF); and
- Bidding at asset level [13].

The resulting solution resembles a real-time market, which is an inherent part of the two-settlement nodal market design. In a European context it could be seen as the inclusion of welfare optimisation in system balancing. This can be attained by using well-known and powerful optimal power flow algorithms, or more precise, Security Constrained Economic Dispatch (cf. **Section 3.5**), to find the activation of bids that minimises total costs, while satisfying all relevant grid constraints.

Allowing the market to freely act until real-time will challenge the system operation and redispatch procedures especially within a system with high shares of variable RES and close-to-real-time trading. A solution with location-based balancing remains essentially a zonal model, with the advantages this implies. It is a hybrid model with some of the advantages of nodal model, mainly in ensuring a feasible and efficient dispatch in real-time, without the major disadvantages. It is probably also easier to implement only in some countries in a co-existence solution, cf. **Section 3.6**.

When combining location-based solutions with the zonal approach in the European system, several solutions are possible [14]:

1. The BSP bids are directly represented in the zonal platform, and the results are corrected to satisfy intra-zonal constraints in a post-AOF process.

2. An aggregate supply curve is constructed before the bids are sent to the zonal platform. This curve attempts to include, to the extent possible, the intra-zonal constraints in a modified bid curve, which does not represent the original bids directly. After the completion of the AOF, the activated bids must be de-aggregated back to the real bids. See also **Section 3.6** for this approach.

3. The detailed grid of the relevant country is directly represented in the AOF.

Options 1 and 2 require some computation time after the completion of the AOF, necessitating changes in the proposed process timing. This also appears to be the case for option 3, as it is difficult to represent the capacities between the detailed and aggregate grids correctly, which leads to deviations.

As a by-product, such a model will also produce nodal prices, but alternative pricing options exist such as average prices, or zonal prices from the European platform for intra-marginal bids and pay-as-bid for the remaining bids (equivalent to splitting balancing and redispatch, as performed by Nordic TSOs today).

Questions

37. Do you consider more locational information in the balancing timeframe to be a solution worth requiring further analysis?

38. Would you recommend any alternative solution to solve intra-zonal congestion in the balancing timeframe?

13 The important property is that the location of the bid in the grid model is known and thus "unit bidding" is not necessary. Some aggregation within uncongested parts of the grid could also be allowed.

14 For more details, cf. the report "System balancing solutions with detailed grid data", prepared by N-SIDE and NHH for Statnett SF, 30 April 2020, available at **https://www.statnett.no/contentassets/3b981e22e5d64179bb22ea9e5b46f515/2020-study---system-balancing-solutions-with-detailed-grid-data.pdf**

3.5 Nodal based models

With Locational Marginal Pricing (LMP) or nodal pricing, the price in each node of the grid reflects the marginal cost of serving an additional unit of load in that particular node knowing the detailed network constraints.

The calculation of LMPs uses a grid model with the voltage level and level of detail corresponding to the desired nodal resolution, typically representing the transmission grid. Flexible generators and demand submit unit-based offers and bids, specifying their nodal location. Bids and offers, resource constraints, network constraints, transmission losses and certain ancillary service requirements are co-optimised. The market clearing is based on Security Constrained Economic Dispatch (SCED) and/or Security Constrained Unit Commitment (SCUC).

One of the main differences between LMP and zonal based approaches is that the physical characteristics of the grid (i. e., all relevant grid constraints) are included in the market clearing in LMP. In traditional zonal models, such characteristics must be dealt with "out of market". It is not necessary to calculate zonal capacities, as the grid as well as the capacities of individual lines (and where relevant, transfer corridors) are directly represented in the market-clearing. For the same reason, redispatch after day-ahead market clearing is not necessary, as grid constraints are taken into account by design.

Typical LMP markets run in two time horizons – day-ahead and real time. The day-ahead market is used to create financially binding schedules that are "simultaneously feasible", meaning that they satisfy all relevant grid constraints. The day-ahead market clearing uses a SCUC process that calculates schedules that reflect transmission constraints, unit dynamic constraints, etc. and a SCED that calculates LMPs excluding non-linear constraints such as start-up cost which are compensated by uplifts payments. The real-time markets typically clear every 5 minutes, using SCED only due to computation time constraints. The real-time market reflects the real time standard operating constraints of generators, demand-side bids and the transmission grid, and the resulting dispatch thus satisfies the described constraints. They are also reflected in the real-time price, at which all remaining imbalances are settled.

LMP markets can co-optimise reserve procurement with the day-ahead market, and also balancing and congestion management in the real-time market.

A nodal model avoids most of the challenges related to bidding zone configuration and capacity allocation. The availability and capability of all resources are known before real time, because the impact of the grid constraints is taken into account in the dispatch decisions. Moreover, the manner in which congestion is handled is more transparent, as constraints largely directly reflect physical constraints. Finally, gaming through the so-called "inc-dec" game[15] is largely avoided, although through market monitoring is required to avoid abuse of market power.

On the other hand, there are also some significant downsides. For example, the implementation time and costs of shifting to a fundamentally different model are high and difficult to estimate. Partly related to this is public and political acceptability, as such a shift would imply major changes for most stakeholders.

15 Cf. Hirth, Lion; Schlecht, Ingmar (2019): Market-Based Redispatch in Zonal Electricity Markets: Inc-Dec Gaming as a Consequence of Inconsistent Power Market Design (not Market Power), ZBW – Leibniz Information Centre for Economics, Kiel, Hamburg.

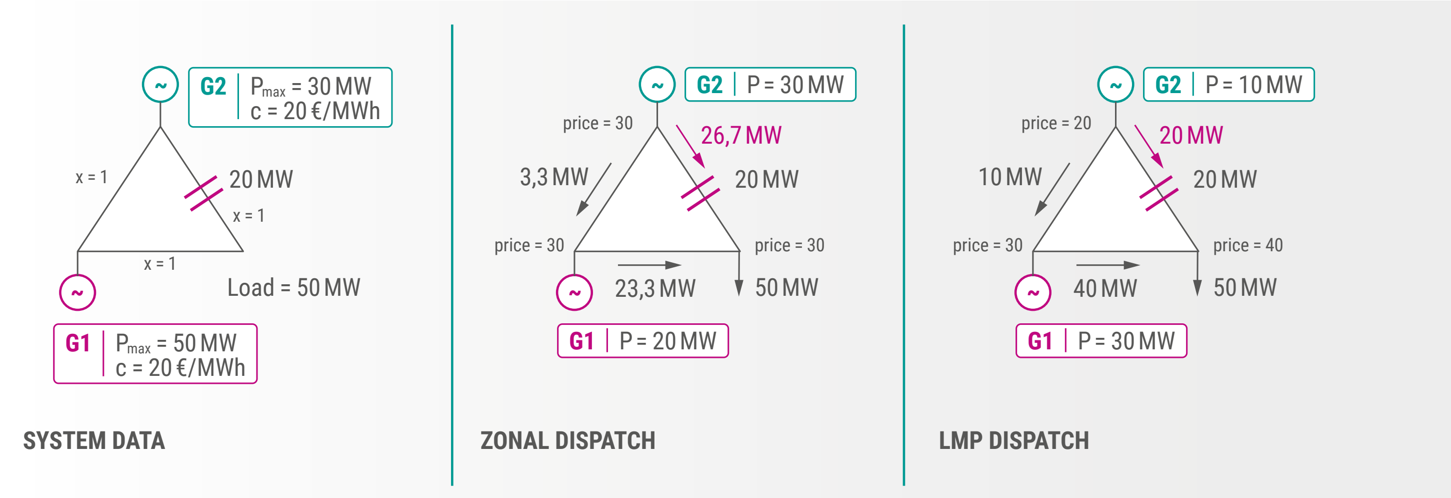

Figure 5: Illustration of the difference between a zonal dispatch and the LMP dispatch. The latter will respect the line constraint, while redispatch is required in the former.

In a zonal market, the uncertainty for market participants is related to price variations over time within each zone and between zones. However, in a nodal market, there is potentially higher uncertainty related to price variations between single nodes. Therefore, an essential feature for nodal markets is the introduction of Financial Transmission Rights, which can be used as an instrument to hedge against nodal price differences. A wide range of literature is available on this topic[16].

ENTSO-E's view is that nodal is not a feasible/desirable option on a European scale by 2030 for various reasons (e. g. public and political acceptability, implementation time and costs or liquidity and cost of hedging). In addition, in a European context, a nodal model would require additional features:

- A level playing field for the demand-side participants. In several US markets, demand is forecasted by the ISO. In Europe, it would be natural to continue with current practice, where demand bids in the market, either directly (i. e., large consumers) or through retailers. The advantage of this is that demand is more involved in the market, and retailers are incentivised to prepare good forecasts and also to increase the focus on demand response. Small scale solar PV could be treated as a part of the demand side.

- A level playing field for variable RES (i. e., wind, large scale PV). Although, variable RES is often forecasted by the independent system operator (ISO) in US markets, it would be more in line with future European market development to fully integrate variable RES as a market participant, on an equal footing with other generation resources.

- As Europe will not be one nodal market in the foreseeable future, the loop flows and market flows created by adjacent market areas require consideration. The exchange with non-market areas creates flows on the transmission lines within the nodal market and can, therefore, increase congestion. In order to provide efficient/correct price signals, such exchanges have to be considered in the LMP algorithm. This requires strong cooperation between both markets, independent of the fact of whether the surrounding non-market area(s) are nodal markets or not, see also **Section 3.6**.

- Consideration of topological measures (switching) in the LMP algorithm. Current nodal markets do not consider topological measures resulting in a potential loss of social welfare. The full optimisation of topology is computationally infeasible, but approximate methods from research could be relevant for implementation.

- Ideally, the distribution level connected market participants should be able to respond to price signals as well while addressing physical constraints in other voltage levels. Locational price signals on the distribution level by introducing distribution-based LMP (DLMP) is one (theoretical) option. It should however also be possible to solve these issues in ways other than through DLMP, which may be difficult to implement from the start, especially due to the large computational complexity.

- A (nodal) intraday market. The large and increasing volumes of variable RES necessitate the possibility for trading when production forecasts improve and change. Intraday trade is possible in nodal markets, but must be done through auctions, as the simultaneous feasibility of all trades must be ensured.

Questions

39. Do you think experience with nodal models can be useful in Europe, and how?

40. What other advantages or disadvantages do you foresee with nodal models in a European context than those mentioned here?

41. How could the increasing participation of distributed energy resources to the balancing market be handled in nodal pricing models?

16 See for instance: William W. Hogan, "Contract Networks for electric power transmission", 1990, revised 1992.

3.6 Coexistence of different market models

Different countries face different challenges that are hard to solve efficiently within the current transmission capacity management model. Specificities such as the generation mix, grid topology, market structure and key actors – and even more political objectives and policy priorities – may make alternative solutions more suitable for some countries.

Against this background, and considering already existing market design differences in Europe, a future where different market design models coexist in Europe is a realistic evolution that deserves careful attention and further analysis.

At the same time, it must be ensured that an efficient coexistence of different market models preserves the benefits of the internal energy market. In the following, we briefly discuss some options for the coexistence of (fully) zonal and nodal market models.

We have identified two main relevant options for integration, first focusing on the day-ahead market.

1. **Sequential zonal-nodal dispatch**
   This approach is presently planned in Poland. First, the whole market in the EU is cleared through a zonal market coupling, identical to the present approach in Euphemia. This gives each country's net position as well as the flows over all interconnectors. Subsequently, the nodal markets are cleared internally or regionally, while satisfying the flows (and consequently net positions) resulting from the zonal market. In the current bidding zones configuration, the difference between zonal market results and resulting physical flows has to be taken into account, so during nodal market calculation, unplanned flows have to be predicted.

2. **Integrated zonal-nodal dispatch**
   In this case, there is only one market clearing process in the day-ahead timeframe and possibly intraday auctions with a full representation of the nodal markets and a simplified representation of zonal markets, which are modelled as one node. This means that the (linear) constraints governing the flows in the nodal markets, as well as the nodal power balances, are added to the market coupling algorithm.

The sequential model only obtains some of the advantages with nodal pricing (mostly in the real-time market), as the initial exchange between countries still faces the challenges generally posed by zonal designs. Market rules in such an approach should be carefully designed to avoid strategic behaviour arbitraging between zonal and nodal clearing.

The sequential approach is simpler from a technical/computational perspective and easy to implement from a zonal market perspective, as the present zonal market clearing does not change. However, it creates serious implementation problem in nodal markets, as the time for nodal clearing is strictly limited, and previously obtained zonal results must be respected.

The Integrated zonal-nodal approach is more versatile and obtains more of the advantages of a full nodal model, as the exchange between countries is to a larger degree controlled by physical conditions in the country with the nodal market[17]. Consequently, it results in more feasible flows and reduced unscheduled flows level. Nevertheless, unscheduled flows will remain, as the zonal part of the market still uses a simplified network model. This may also cause results for nodes close to zonal market to be distorted. In the integrated approach, the market is solved in one run. There is, therefore, no need to run zonal and nodal clearing sequentially, leaving more time for both processes. Furthermore, the strategic behaviour issues indicated above do not materialise, since market participants in the nodal market only are exposed to nodal prices. The major challenge with this approach is a significant increase in problem size of the market coupling model, which is already fairly computationally demanding.

As intraday auctions will soon be introduced at EU level, zonal and nodal intraday auctions may be integrated using the same approaches described above. They will have similar features as in day-ahead, however, due to the short gate closure time, the sequential approach may be problematic for nodal markets because the remaining time will be strictly limited.

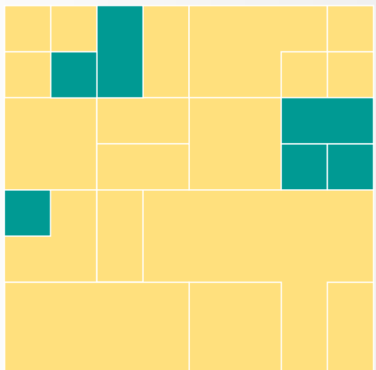

Figure 6: Zonal (yellow) and nodal (green) models within the same system

17 A recent paper analyses this design alternative for the Polish case: Endre Bjørndal, Mette Bjørndal, Hong Cai, Evangelos Panos, "Hybrid pricing in a coupled European power market with more wind power", European Journal of Operational Research 264 (2018) 919–931.

In real time, it is necessary to identify a method for the nodal systems to interact with the upcoming European platforms for RR, aFRR and mFRR, considering that the real-time market would optimise several products simultaneously, while the planned platforms operate independently. The simplest, sequential, interface between nodal and zonal markets may be developed using bids conversion as foreseen in EBGL art 27 for central dispatching TSOs. A nodal market may, on the basis of available nodal bids and the current system state, create a so called "net export curve" (NEC), which will represent the possibilities of change of XB schedules of the nodal country ("bidding zone") and costs associated to these changes. This curve has a form of the balancing energy bids used in the zonal market and will be submitted to balancing platform(s). The platform will clear balancing markets, merging bids submitted directly from zonal TSOs and submitted via NEC from nodal TSOs. If offers from NEC are used, this will result in a change of the net position of the nodal country. This new net position is an input for the next run of the nodal market, which will decide which physical units would realise this change. More advanced, but also complicated, options will be the inclusion of the detailed model for nodal markets in balancing platforms.

As long as it can be ensured that the efficiency of the internal market can be preserved, coexistence between several models can solve challenges for some countries, while also offering a path to the testing of alternative solutions, which can be difficult at the EU level.

Questions

42. Under which conditions do you think a nodal market could be a relevant solution for some countries?

43. Do you foresee other challenges or solutions than those mentioned here with respect to the interaction between zonal and nodal solutions?

3.7 Redispatching and local flexibility markets

The zonal market design – by definition – does not integrate infrastructure constraints within a zone in the market mechanism. Hence, there can be a deviation between market outcomes and physics of the grid and subsequently, the need for congestion management. Managing grid congestions can be performed on a cost-based (mandatory participation with reimbursement of costs) or a market-based approach.

Local flexibility markets are often discussed today as a tool to take advantage of the flexibility potential of distributed energy resources (DER) and demand response (DR) connected at the distribution level. Considering the expected increase of both DER and DR in the coming years, as well as the business opportunities offered by digitalisation, new market actors (e. g. aggregators, virtual power plants) and new market platforms, local flexibility markets could play a key role in the future energy system. For this reason, it is important to assess – based on current trends of the numerous initiatives and pilot projects – which are the possible options for their evolution and key market design questions for debate.

Local flexibility markets are meant to be a tool for managing congestions more efficiently, possibly avoiding or deferring new grid investments. For TSOs and DSOs, this instrument can be an additional tool for congestion management (especially relevant for distribution networks and small-scale resources). From the perspective of market actors, flexibility markets offer (additional) opportunities to better optimise their production and consumption, and business opportunities to value their flexibility and/or to reduce their energy bills.

Adequate coordination between TSOs and DSOs is crucial when designing this kind of markets.

A central advantage of local flexibility markets is the ability to integrate DSR and DER units into the redispatch. Integrating these assets into a cost-based redispatch would require network operators to assess each asset´s individual willingness to pay in order to calculate their compensation, which would be an extremely difficult or impossible task. However, as recognised by a number of studies[18], there are at least two fundamental problems identified in market-based redispatch:

a. The impact on the electricity market due to undesirable bidding incentives (inc-dec gaming); and

b. locational market power.

In the literature[19], several arguments are discussed regarding mitigation measures that might help prevent an undesirable market outcome and limit potential gaming incentives for flexibility providers. These range from bid caps, market monitoring measures, and randomised bid selection to long-term contracts if too few suppliers are offering flexibility. Bid caps can be introduced explicitly or – as in so-called "hybrid models" – implicitly. The latter implies that flexibility bids are only chosen by the system operator if it is cheaper than regulated flexibility which is remunerated on a cost-based approach.

18 See for instance the report by Consentec and Neon: "Cost- or market-based? Future redispatch procurement in Germany" (2019).

19 See for instance NODES AS: Market-Based Redispatch in the Distribution Grid – Why it works! (2020) or Enera: Using Enera's experience to complement the upcoming redispatch regime with flexibility from load & other non-regulated assets (2020).

With regards to the different approaches of local flexibility markets, a number of recent studies and reports[20] have recently reviewed existing initiatives. Several EU-funded R&D projects have also investigated how these solutions can be integrated into existing markets and how they can be scaled up across Europe: e. g. Interrface, OneNet, EU-SysFlex, Coordinet.

This variety of initiatives can be categorised according to different dimensions, such as for instance:

- **What product is traded:** current platforms address active congestion management and several also address balancing services that entail either or both an availability product (MW) and an activation product (MWh). There is currently no standardisation of these products except in the United Kingdom, where TSO and DSOs have jointly defined four standard flexibility products to support the liquidity of local flexibility markets[21]. This may, however, evolve with the implementation of Article 32 of the Electricity Directive. In addition, several projects explore the potential use of balancing products (mFRR in particular) for transmission congestion management purposes. In the future, other types of products could be traded, for instance specifying the speed of response required or pertaining to reactive power management;

- **Who is the primary buyer:** most existing projects enable flexibility provision to TSOs and DSOs. Although there is a strong focus on DSOs to offer them additional means to deal with network congestions, several platforms intend to also extend the offering of their flexibility services to TSOs. In theory, other market parties can be a buyer, although peer-to-peer platforms today remain rare examples

The Active System Management report[22] further proposes a categorisation of flexibility markets with three main models which vary according to the level of coordination between TSOs and DSOs and the degree of integration with balancing and intraday timeframes.

Questions

44. How can distortions and inc/dec gaming in market-based redispatch be addressed/mitigated?

45. What type of alternatives (e. g. capacity-based payments) exist to efficiently make use of distributed flexibility sources?

46. What recommendations do you have for the development of local flexibility markets based on existing initiatives?

47. Should EU legislation attempt to define some fundamental common principles (e. g. degree of integration with existing wholesale markets, products standardisation, etc.)?

20 See for instance Tim Schittekatte and Leonardo Meeus, 'Flexibility Markets: Q&A with Project Pioneers', Florence School of Regulation Working Paper (2019) or Julia Radecke, Joseph Hefele and Lion Hirth, 'Markets For Local Flexibility in Distribution Networks', ZBW – Leibniz Information Centre for Economics (2019).

21 Energy Network Association (2020) **https://www.energynetworks.org/creating-tomorrows-networks/open-networks**.

22 ENTSO-E, CEDEC, E.DSO, Eurelectric and GEODE (2019).

4 Resource Adequacy and Investment Signals

The electricity system is rapidly evolving, from a system dominated by traditional fossil fuels generation towards a low-carbon system, dominated by renewables, where consumers are able to actively participate to the energy market and with emerging storage technologies. However, this rapid transformation changes the market conditions for new investments, leading to concerns that electricity markets as they existed in the past may not provide sufficiently effective investment signals to ensure the resource adequacy of the system.

In this chapter, we will present possible options to improve the effectiveness of such market signals to ensure resource adequacy.

4.1 Main market design options to ensure resource adequacy

To ensure resource adequacy in 2030, we foresee three main market design options:

- **Enhanced Energy Only Markets** (EEOM), a model where the level of resource adequacy is not set exogenously but as an outcome of the EOM itself, without additional payments for the provision of capacity (except for some ancillary services).
- **Capacity Markets** (CM), a market design where regulatory intervention is required to ensure the adequacy of the system. Such regulatory intervention typically consists in payments to market parties in exchange for their availability to generate (or to reduce consumption) when mostly required by the system.
- **Strategic Reserves** (SR), based on a targeted regulatory intervention: specific contracts for the provision of capacity are signed only with a limited number of resources, which are considered necessary to reach a desired level of adequacy not guaranteed by the EOM. Such capacity is typically provided by resources that otherwise are decommissioned, and they are not allowed to participate in the energy markets.

As market conditions (i. e., generation mix, demand patterns, grid topology, policies) differ between countries, we believe it is not possible to recommend one option over another for the whole of Europe. Moreover, the continuous development in new technologies could lead to a change in the highest-performing and most suitable market design option to be adopted within one single market. Nevertheless, we have identified some key enhancements for each one of the market design options, aimed at improving the adequacy of the system.

As presented in our recent work on 2030 market design, we believe that electricity markets should be designed in the future to deliver more clear and effective locational signals, so to help addressing the increasing challenges of grid congestions. Such locational signals could be delivered not only via the energy markets in wholesale prices as explained in Chapter 3, but also via investment price signals typical of more "capacity-based" market mechanisms such as Capacity Markets, Strategic Reserves or even RES Support Mechanisms. This could imply, for instance, location-specific tenders, or differentiated prices or capacity requirements depending on the location. Although further analysis is needed to outline the different options and their pros and cons, we believe this approach deserves careful consideration as it has already been implemented in some countries.

Questions

48. Do you agree that all three models described above could be suitable for European countries in 2030?

49. Is there any additional market model which would be suitable for European countries in 2030?

4.2 New Capacity Mechanisms models

4.2.1 Capacity Mechanisms with flexibility requirements

Under this market design option, the TSO firstly determines the "residual load curve" to be auctioned in the CM. This curve is calculated as the difference between electricity demand and the expected generation from wind and solar[23]. Most importantly, this curve must be representative of a typical critical day in which it might be difficult to ensure the adequacy and the safety of the system.

In a second step, the TSO "splits" the residual load curve in different components. This concept is illustrated in Figure 3, which represents the load net of vRES generation in a "critical" day. For example, we can imagine Figure 3 to represent a critical summer day in a Southern European country, where the residual load in the middle of the day is low due to the contribution from solar generation. However, the residual load increases significantly in the evening due to a combination of increasing load (i. e. when people go back home after a day at work) and decreasing solar generation as sunset approaches.

In this example, we have identified 3 components of the residual load, reflecting the different requirements to meet the needs of the system.

- A "baseload" component represents the amount of capacity expected to provide energy in a continuous manner for most of the year; no specific eligibility requirements are allocated to this baseload component.
- A "ramping" component should be provided by those resources which are capable of ramping up and down very quickly to follow the steep movements of the residual load curve.
- Finally, a "peaking" component should be provided by those resources expected to contribute to the adequacy of the system only during a limited number of hours per year.

The details of this market design option (e. g., how to properly define the residual load curve and which components should be considered), as well as the synergies between this CM option, the energy markets, and support schemes for renewables, require further assessment. In particular, the interaction between the "CM with flexibility requirements" and the AS market needs to be addressed appropriately. In fact, whereas on the one hand this CM option helps to ensure there are sufficient flexible resources in the system, on the other hand, there is a risk of over or under procuring the required flexible resources when capacity contracts are signed years ahead of delivery, leading to potentially higher costs for consumers.

Another aspect to consider when designing a CM with flexibility requirements is the definition of the rules for remunerating contracted parties. One option is to have different clearing prices for each component of the residual load. This aspect also needs to be investigated properly in other studies and is out of scope of this paper.

Questions

50. Do you see capacity mechanisms with flexibility requirements as a promising option for further analysis?

51. What are in your view the main potential advantages and drawbacks of capacity mechanisms with flexibility requirements?

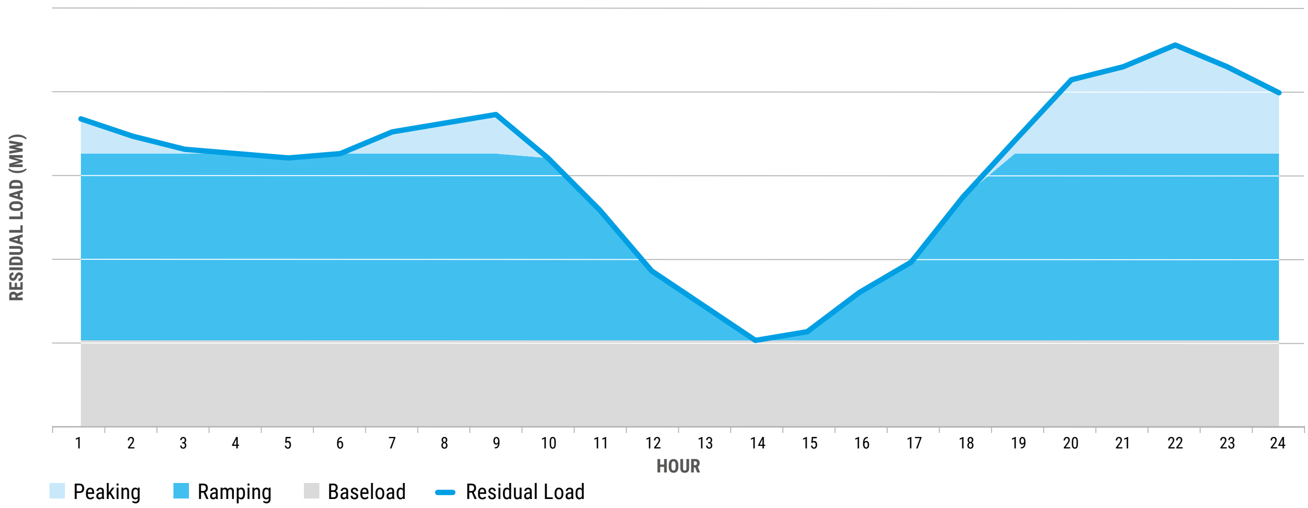

Figure 7: Residual load splitting

23 This implicitly assumes that wind and solar cannot participate in the CM. An alternative viewpoint is discussed in **Section 4.4**

4.2.2 Capacity Subscriptions

In all existing CM models, the demand for capacity is determined by third parties (i. e., supplier, TSO, regulator etc.), and not directly by the consumer. This is different for Capacity Subscription[24], where consumers buy the amount of generation capacity they are going to require during system scarcity periods. They buy capacity subscriptions from providers of firm capacity (e. g., generation and storage). When a consumer buys a capacity subscription of, for instance, 4 kW, they are guaranteed that they can consume electricity up to this capacity level under all conditions. When the energy market is short of generation capacity, e. g., during a period with little solar and wind energy, the TSO activates so-called Load Limiting Devices (LLDs) that are installed at each consumer site. Thus, consumers must restrict their consumption to the levels that they contracted. In return, they have the certainty that this capacity is available. When there is no shortage of generation capacity – most of the time – consumption is unrestricted. A high-level illustration is given below.

Risk reduction for consumers and generation

Because physical shortages are avoided (except possibly in exceptional events), scarcity prices do not normally occur. A capacity subscription may therefore be considered as a physical option contract: by paying for the capacity subscription, a consumer obtains the right to consume electricity at a contracted price at any time, avoiding scarcity prices. For generation companies, the benefits are that the demand for reliable capacity is made explicit and that the payments are spread out over time. In fact, this system turns reliable capacity into a product with a steady remuneration.

24 Doorman G.L. (2005), Capacity subscription: solving the peak demand challenge in electricity markets, IEEE Transactions on Power Systems, 20 (1), pp. 239–245. De Vries L.J. (2007), Generation adequacy: Helping the market do its job, Utilities Policy, 15 (1), pp. 20–35.

Capacity subscription: based on consumers' demand for capacity

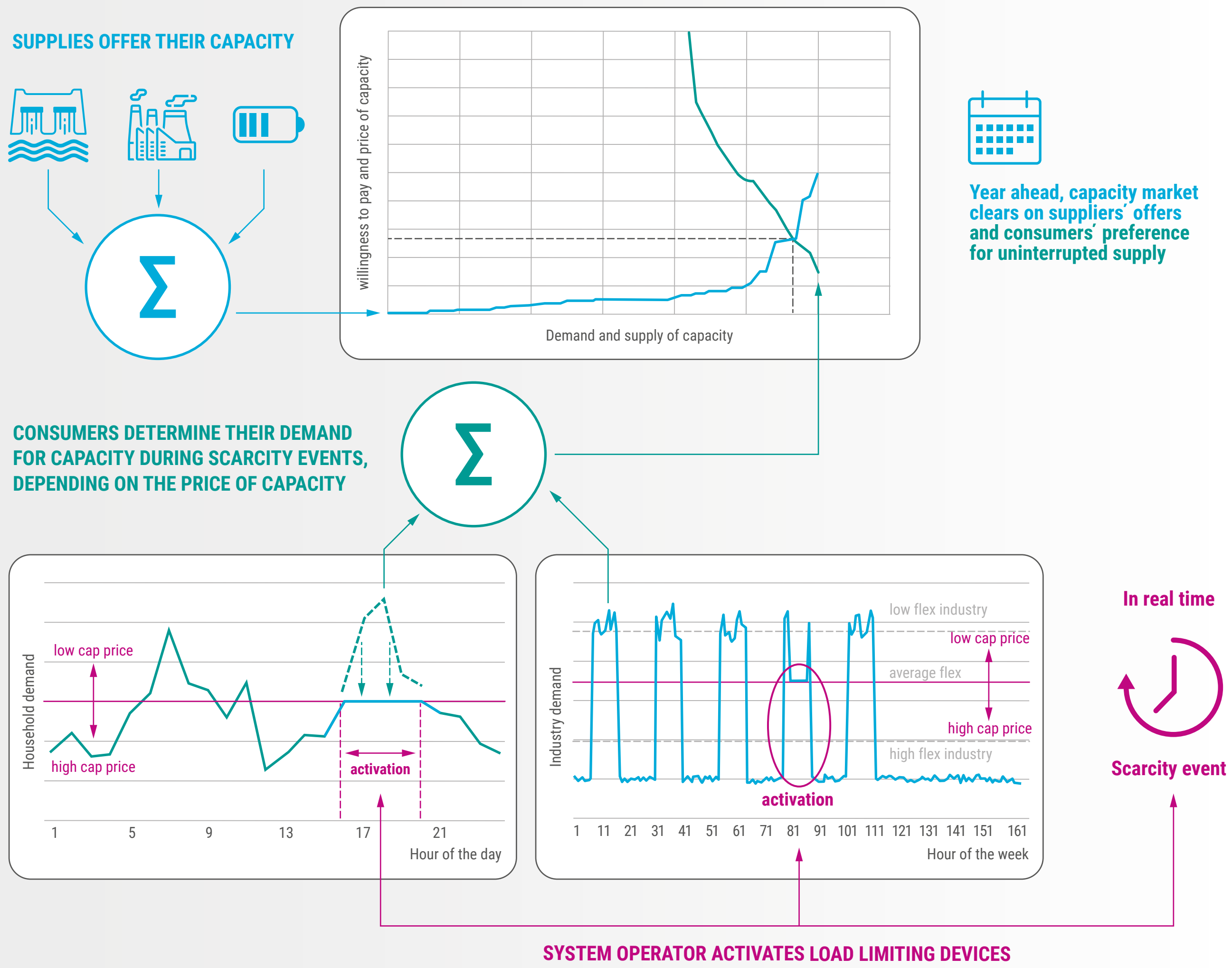

Figure 8: Capacity subscription: based on consumers' demand for capacity

Consumers

Crucial questions for consumers include how much capacity they need, when they need it, how it coincides with system scarcity, and if they have alternative means to reduce their need for capacity.

Based on available data and forecasts, apps and websites in the future should be able to support consumers to make choices that match their preferences. Moreover, in a system with the widespread use of Capacity Subscription, there will be a strong demand for such solutions, incentivising their rapid development.

Demand flexibility

A compelling feature of Capacity Subscription is that it creates incentives to keep demand below the subscribed capacity and to develop the technology for this purpose. If Capacity Subscription is widely used, millions of consumers will be interested in controlling their demand, creating opportunities for companies to develop and sell solutions

Capacity subscription turns reliability into a private good

Ensuring system adequacy by having sufficient generation capacity is the way in which consumers' preferences for uninterrupted supply are normally satisfied. Obviously, in this setting system adequacy has strong common good characteristics. With Capacity Subscriptions, consumers weigh the cost of capacity against their preferences for unlimited supply. If the price of capacity is high, industrial consumers will, over time, redesign their production processes to be able to reduce their need for capacity. Households and services will similarly have incentives to look at ways to reduce demand when necessary. Capacity Subscription thus has the unique feature that it reveals the need for capacity in the market, based on consumers' preferences for uninterrupted supply, which internalises system adequacy in the market: the generation part of system adequacy becomes a private good.

Capacity supply

The main capacity suppliers are the generators. They can sell the capacity they expect to have available during periods of system scarcity. When a scarcity event occurs, generators need to demonstrate their availability by bidding in the relevant markets, day-ahead, intraday and balancing. There needs to be a significant penalty for non-compliance to avoid gaming.

Activation of the LLDs and the role of the TSO

The main role of Capacity Subscription is to ensure the balance between demand and supply at the system level. In this context, the TSO is the obvious party to activate the LLDs. While actual activation will only occur close to real-time, the TSO issues advance warnings before the day-ahead market clearing and subsequently throughout the day until (close to) real-time. Consumers need to be "notified" in advance to be prepared.

Capacity auctions

Annual auctions are the primary marketplace. The auctions need to be held well in advance of the season when residual demand (demand minus vRES production) peaks. There is no lead time, i. e. only existing capacity can participate. However, owners of new plants know that, once a plant is commissioned, it will receive revenues from selling capacity. Additional auctions will be required to address changes in supply and demand of capacity, but this may also be solved through continuous trade. Participation in capacity auctions or continuous capacity trade is not relevant for small consumers – instead, they could buy capacity from the retailer, much in the same manner as they buy energy today. Small consumer buy capacity from the retailer who participates in wholesale capacity trade on their behalf.

Simplified solution for small consumers

Household consumers can be provided with a default capacity subscription that is based on their peak capacity usage during the previous year, without the physical limitation. There would be no immediate penalty for exceeding the capacity level, but in this case, the next years' capacity subscription would be based on their new consumption peak. This way, consumers do not need to think about buying capacity subscription yet they still have a strong incentive for reducing their contribution to the system consumption peak. Consumers who want to reduce their cost can opt into the system by buying a capacity subscription and committing to that level of peak consumption.

Questions

52. Do you consider the capacity subscriptions model as a promising option for further analysis?

53. In your view, what are the main potential advantages and drawbacks of the capacity subscriptions model?

4.3 Scarcity Pricing

Preamble (24) of Regulation (EU) 2019/943 recommends scarcity pricing to "encourage market participants to react to market signals and to be available when the market most needs them and to ensure that they can recover their costs in the wholesale market" and to "contribute to the removal of other market distortive measures [ ] in order to ensure security of supply". The Regulation does not explicitly address scarcity pricing in specific articles, however establishing a shortage pricing function based on scarcity for balancing energy should be considered when addressing any identified resource adequacy concerns, as mentioned in Article 20 of this Regulation. While the Regulation does not provide any guidelines on how scarcity pricing should be implemented in practice[25], the concept as such is not new and has been widely described by academics. As per the shortage pricing function in balancing – often described as Operational Reserve Demand Curve (ORDC) – this has also been implemented in several markets such as the ERCOT market in Texas or similarly in the SEM (Single Electricity Market) in Ireland.

A shortage pricing function aims at "artificially" raising the imbalance price above the price which would otherwise be achieved by the market itself. In the SEM, scarcity pricing is achieved by implementing a price floor to the imbalance price at times of scarcity. In the ERCOT market, scarcity pricing is achieved by a "price adder", which applies to the real time price. The value of the "price adder" varies as a function of the available reserves: when the available reserve is below the minimum reserve requirement, the probability of load shedding is imminent, and the adder increases the real time price to the value of lost load (VoLL). The impact of the adder on the real-time price is illustrated in Figure 2. In contrast, when available reserves are much greater than the minimum reserve requirement, the value of the adder is zero. The overall impact of scarcity pricing is to increase prices in times of scarcity, which in turn provides an incentive for the consumer to reduce their demand in times of scarcity. Whether such prices can be a decisive incentive for generators to invest in new generating capacity is debatable as it depends on the (expected) frequency, magnitude and long-term recurrence of such prices, as well as on numerous other exogenous variables influencing investment decisions. As such, the impact of scarcity pricing on adequacy has still to be demonstrated, and even more so for the European context.

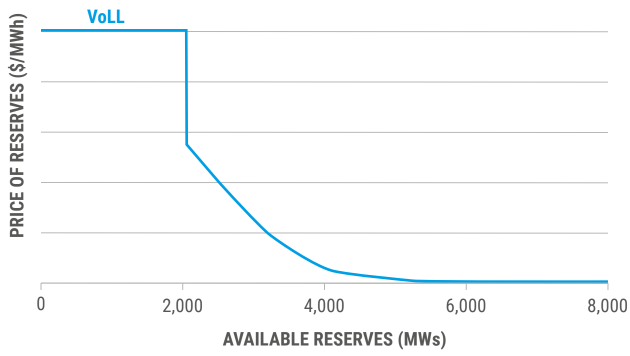

Figure 9: Impact of the ORDC on the real-time price in the ERCOT market; Sources: **https://hepg.hks.harvard.edu/files/hepg/files/ordcupdate-final.pdf**; **https://www.nrg.com/insights/energy-education/what-texas-businesses-need-to-know-about-scarcity-pricing-this-s.html**

Elia, the Belgian TSO, has conducted a study[26] to assess the impact that the introduction of the ORDC function would have on the electricity market and on stimulating new investments in the energy market. Based on a methodology provided by the Center for Operation Research and Econometrics UC Louvain), price adders have been applied to 2017 historical imbalance prices. The application of this methodology has not significantly impacted the value of imbalance prices, due to the rare occurrence of low remaining margin across the studied timeframe. However, the study has shown that the value of the adder is greatly impacted by certain modelling parameters (e. g. assumptions on VoLL, calculation of the capacity margin, etc.), therefore the methodology to calibrate such parameters requires further study before being applied to any current market design, particularly in a cross-border (balancing) context as foreseen in Europe. These findings have been confirmed by a recent 2020 study[27] which shows the need to carefully address in a cross-border context market design and legal questions, such as whether State Aid rules apply or not.

25 In any case, we assume that if scarcity pricing was to be introduced in Europe, it would be covered by the scarcity component defined in Imbalance settlement harmonisation methodology (ISHM).

26 Elia, Study Report on Scarcity Pricing in the context of the 2018 discretionary incentives, December 2018

27 Elia, Final Report on Elia's findings regarding the design of a scarcity pricing mechanism for implementation in Belgium, December 2020.

There are three key aspects which need to be considered before introducing the ORDC within the energy market.

1. Firstly, to maximise the positive impact that the introduction of the ORDC function has on system adequacy, and to avoid inefficiencies or market distortions, all market participants must be exposed to the imbalance price (and therefore to the ORDC function). Although such a principle is relatively straight-forward to apply in a system where reserves and energy are entirely managed by a single operator, as in the ERCOT market, the question becomes more complex for systems where reserves are shared between multiple systems and roles of energy provision and reserves provision are separated, which is typical across European markets. When considering the implementation of scarcity pricing, the European context and market design should also be considered to avoid introducing market inefficiencies and market distortions.

2. Secondly, for the ORDC to impact system adequacy, there must be a backward propagation of the real-time imbalance price up to the forward markets, as investment decisions occur (significantly) before real-time. However, although forward prices are indeed correlate to a certain extent with real-time prices, the effective backward propagation of spot prices to forward prices is not conclusive in related literature[28]. If the backwards propagation remains insufficient to stimulate investment, real-time security of supply is not improved. Another persistent issue is also the risk-averse nature of investors, as stated in Newberry (2020)[29]: "To summarize, the problem is not that there are no futures and forward markets, only that their tenor is not matched to that needed to reassure financiers lending at an acceptable cost of capital", for which ORDC/scarcity pricing alone also fails to provide a solution. The ORDC/scarcity pricing function alone may, therefore, not be the optimal choice to deal with such a risk. More forward-looking solutions (e. g. setting a mandatory provision of a certain percentage of demand side response by suppliers as mentioned in **section 2.1.4**) could be more suitable.

3. Lastly, it should, however, be noted that a shortage pricing function or other forms of scarcity pricing are not exclusive to the EOM. The ORDC/scarcity pricing solution is often proposed in academic literature in combination with – and not as a substitute of – capacity mechanisms.

Questions

54. Which potential benefits or drawbacks do you foresee with the implementation of scarcity pricing in your market?

55. Do you have any specific suggestions on how scarcity pricing could be implemented?

4.4 RES Financing

The unprecedented growth in renewable generation worldwide has so far been dependent on support schemes. There are diverging views as regards the future need for renewable support mechanisms.

One view is that necessary improvements to existing markets (including appropriate pricing of CO_2) will result in prices that, on average, will generate revenues sufficiently large to finance ever-cheaper renewable generation. An opposing view is that the increasing share of renewables will lead to a "cannibalisation effect": increasing penetration of variable renewable technologies will have a downward impact on prices captured by such technologies, therefore, resulting in a continued need for support.

In any case, support mechanisms should distort as little as possible the functioning of wholesale markets, exposing RES generation to price signals and incentivising their participation in the wholesale markets and to the balancing markets in particular. ENTSO-E has reviewed in a separate paper different types of support schemes and is of the opinion that feed-in premiums, quota systems, and investment subsidies interact more efficiently with wholesale markets as opposed to feed-in tariffs. To determine the level of support efficiently, controlling the overall amount of subsidy that governments commit to, a competitive mechanism such as auctions are necessary (as required by current EU regulation[30]). In particular, auctions that specify a feed-in premium for a fixed number of MWh (which is, in effect, capacity support) appear particularly efficient.

28 REFS: Bessembinder H., Lemmon M.L. (2002). Equilibrium pricing and optimal hedging in electricity forward markets; The Journal of Finance 57(3) pp. 1347–1382. Botterud A., Kristiansen T., Ilic M. (2009). The relationship between spot and futures prices in the Nord Pool electricity market; Energy Economics, Volume 32, Issue 5 and Lucia J.J, Torro H. (2008). Short-term electricity futures prices: Evidence on the time-varying risk premium. Working paper.

29 David Newbery, Capacity Remuneration Mechanisms or Energy-Only Markets? The case of Belgium's market reform plan, March 2020.

30 Member States can however award support to small scale installations (e. g. rooftop PVs) and demonstration projects without competitive bidding processes as these would not be appropriate.

Capacity-based support schemes on top of the market revenue also represent good practice as they minimise market distortions. Some authors[31] also recommend this type of support schemes as one of the key elements of a "2nd generation" high-RES market design, which would provide better price signals, better incentives for RES investment and operation, and greater system flexibility.

Corporate sourcing of RES via power purchasing agreements (PPAs) between corporate energy users and RES developers is also considered as an increasingly important tool to drive RES development. Already widely used in the US, these instruments are also gaining traction in Europe: in 2015 – 2019, the amount of RES electricity supplied via corporate PPAs in Europe tripled from 847 MW to 2,487 MW. The need to facilitate further PPAs by removing regulatory and administrative barriers is since 2018 also a requirement of the RES Directive.

With regards to tendering, current schemes in Europe (further described in some papers[32]) have been fairly successful in attracting RES generation in recent years. Tenders for offshore wind, in particular, have in some countries awarded contracts with zero-subsidy bids. Tenders for RES technologies could also allow the participation of hybrid units, such as vRES combined with batteries, as already implemented in Spain. This type of hybrid units can bring some benefits to the system by improving the adequacy and reducing the curtailment of vRES technologies.

Lastly, to coordinate better RES development with grid development, the inclusion of locational elements in support schemes or in auctions may be necessary (e. g. by limiting the amount of new capacity in already congested areas).

RES and Capacity Mechanisms

It is often claimed that variable renewable technologies are unable to provide any significant contribution to the security of electricity supply. On the contrary, many studies have shown such an ability, although the contribution provided during times of system stress is limited as the availability of the variable resource is typically scarce during these periods. The contribution varies greatly with the characteristics of the system and with the penetration and diversity of installed variable renewable technologies.

Wind and solar technologies are already allowed to participate in CMs, with de-rating factors applied to take into account the effective contribution that these technologies provide to the security of supply. The methodology used to calculate the de-rating factors for variable renewable technologies needs to be tailored to the characteristics of the system and the expected evolution of the generation mix. Stochastic approaches are preferable and, due to the rapidly changing character of systems when the renewable shares increase, model simulations of future system conditions are better suited than projections based on historical data.

Some countries in Europe have forbidden the participation of subsidised renewables to CMs in order to avoid double support; however, there are cases where such participation is allowed. In such cases, it is important that the mechanisms for renewable support and CMs are aligned, to avoid undue double support.

Questions

56. What type of RES supports is more fit for purpose for the 2030 power system?

57. What other market design elements can facilitate investments in RES to achieve EU climate objectives?

58. What are the best practices for the design of RES tenders?

59. How should capacity mechanisms consider the participation of RES?

31 David Newbery, Michael G. Pollitt, Robert A. Ritz, Wadim Strielkowski (Renewable and Sustainable Energy Reviews 91), 'Market design for a high-renewables European electricity system', 2018.

32 2nd CEER Report on Tendering Procedures for RES in Europe, 2020.

4.5 Ancillary Services

When examining market design to ensure resource adequacy for future decarbonised power systems, Ancillary Services play an increasingly important role relative to current power systems which have a large proportion of conventional power plants. Future power systems with a high penetration of weather dependent (wind and solar) generation will need to have an evolved operational policy to ensure system security. As the constituent generation mix in the system will be radically different from today in many countries, the market design will need to ensure there is adequate supply to meet demand. Moreover, the market should provide incentives for units to support TSOs in optimising the frequency, voltage, and other services that they can provide. This will be necessary to ensure that the system is not just adequate in terms of capacity but also adequate in terms of the overall resources available to securely operate the power system.

Earlier sections of this paper have discussed congestion management and balancing (**Section 2.3.2**) redispatching and local flexibility markets (**Section 3.7**), and the future need for a more dynamic use of the transmission and distribution grid integrate energy from variable and distributed resources. Complementary to this is the use of ancillary services to mitigate the technical scarcities, for example inertia, that arise when conventional power plants are displaced by non-synchronous units. The risk of such technical scarcities has already been widely analysed by ENTSO-E system needs studies[33] in the context of the Ten-Year Network Development Plan (TYNDP). Minimum levels of provision of services such as reserve and reactive power are often mandated from units through grid code requirements. However, as conventional generation is displaced by non-synchronous generation such as wind, the inherent characteristics of the units supplying energy to the grid change. New non-conventional technologies such as wind, solar, demand response and distributed generation can be required to meet minimum standards of AS provision through grid codes. However, as the range of system services required to manage the power system becomes more diverse, an alternative to mandating service provision through the grid code alone is to provide financial incentives for service providers to exceed their grid code requirements and to design additional services outside the grid code to meet power system needs when there is a high penetration of variable generation on the system. Such services may be provided by a range of technologies and by both transmission and distribution-connected units.

An example of the implementation of such a framework is Ireland and Northern Ireland where a suite of enhanced AS or "system services" have been developed to complement the existing reserve and reactive power services.

By designing an appropriate framework which provides for the higher visibility and reliability of potential revenues from AS markets, it should be possible to ensure that appropriate services are available to the TSOs to manage the system. Such a framework will need to provide sufficient investment certainty to potential service providers while ensuring the flexibility to account for changing TSO needs as the power system further evolves. Such arrangements could work in tandem with existing energy markets and Capacity Mechanisms to ensure not just capacity adequacy, but overall resource adequacy in the power system of the future.

Questions

60. Do you see potential for the development of new frequency ancillary services?

61. Which non-frequency ancillary services are more suited for market-based procurement?

62. Do you have suggestions on how to best ensure that market participants provide the necessary system inertia to the system?

63. Would you recommend any other solution for ancillary services in 2030?

64. Is there any other key market design area not addressed in this paper which deserves particular attention to enable the achievement of European energy and climate goals for 2030?

33 See for instance the latest System dynamic and operational challenges January 2021 – **https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2020/Foropinion/IoSN2020_Systemdynamicandoperationalchallenges.pdf**

5 Stakeholder Consultation and Next Steps

As mentioned in the introduction, the key objective of this paper is to stimulate a discussion with all key European stakeholders on the market design challenges and the possible market evolutions for 2030 and beyond. The market design webinar organised on 12 October 2020, attended by more than 500 participants, represented the first milestone of this discussion. With this paper, we are now propose a more elaborated version of the ideas already presented few months ago. While it was not our intention to deep-dive with a technical analysis of all the various options, we hope that the high-level descriptions provided in this paper will be sufficiently clear to electricity markets experts to provide us with concrete feedback.

To facilitate stakeholders' feedback on what we consider the most relevant issues, we have included specific questions for each section of the document. We hope to receive written answers on all or most of them; however, readers and respondents should feel free to reply only to a subset of questions as well as more general market design comments not particularly relevant to any of the specific sections of this discussion paper (**see questions 64**).

Responses to the stakeholder consultation on this discussion paper should be submitted via the dedicated ENTSO-E web-based platform at this **link** by no later than Friday 14 May. For specific enquiries please email **market@entsoe.eu**

ENTSO-E will review carefully all contributions received and organise a dedicate webinar on 10 to discuss with all major stakeholder associations and individual contributors the outcome of this stakeholder consultation, focussing in particular on the market design areas and questions which will receive the most interest. A conclusion paper summarising the key takeaways of the stakeholder consultation and the dedicated webinar will follow.

Glossary

ACER	Agency for the Cooperation of Energy Regulators
aFRR	Frequency restoration reserves with automatic activation
AOF	Activation Optimisation Function
AS	Ancillary Services
BSP	Balancing service provider
CACM	Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management
CEE	Central Eastern Europe
CM	Capacity Markets
DC	Direct current
DER	Distributed energy resources
DLMP	Distribution-based Locational Marginal Pricing
DSR	Demand side response
EBGL	Guideline on electricity balancing
EEOM	Enhanced Energy Only Markets
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FIP	Feed-in-premiums
FB	Flow-based
FCA	Forward capacity allocation
FRR	Frequency restoration reserves
HVDC	High voltage direct current
LMP	Locational Marginal Pricing
LT	Long-term
mFRR	Frequency restoration reserves with manual activation
NEMO	Nominated electricity market operator or power exchange
ORDC	Operational Reserve Demand Curve
OTC	Over-the-counter
PPA	Power purchasing agreements
PTDF	Power Transfer Distribution Factor
PST	Phase shifting transformer
PV	Photovoltaic
RES	Renewable energy sources
RR	Re: 210354_entso-e_pp_financeability Replacement reserves
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SEM	Single Electricity Market
SR	Strategic Reserves
TSO	Transmission system operator
TYNDP	Ten-Year Network Development Plan

The terms used in this document have the meaning of the definitions included in Article 2 of the CACM, FCA and EB regulations.

Drafting team

Bruno De Wachter (Elia / Project Team convenor), Gerard Doorman (Statnett), Salvatore De Carlo (Terna), Christoph Neumann (TenneT), Frederik Paul Sapp (Amprion), Kamil Smolira (PSE), Miguel Ángel Martínez (REE), Charles Payement (RTE), Steve Heather (NG ESO), Marco Foresti (ENTSO-E)

Publisher

ENTSO-E AISBL
8 Rue de Spa
1000 Brussels
Belgium

www.entsoe.eu
info@ entsoe.eu

Design

DreiDreizehn GmbH, Berlin
www.313.de

Images

Title © iStock @imaginima; page 11 © iStock @metamorworks; page 15 © iStock @gorodenkoff; page 17 © Swissgrid

Publishing date

31 March 2021

European Network of
Transmission System Operators
for Electricity

entsoe