Whitepaper

ELECTRICITY MARKET DESIGN 2030-2050: SHAPING FUTURE ELECTRICITY MARKETS FOR A CLIMATE-NEUTRAL EUROPE

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Electricity Market Design 2030-2050: Shaping Future Electricity Markets for a Climate-Neutral Europe

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Preamble

Speeding up the energy transition in the European Union (EU) is a major task to quickly reduce harmful greenhouse gas emissions. Market design plays a crucial role in the decarbonization of the European energy system, driving the expansion of both Renewable Energy Sources (RES) and accompanying flexibility sources. In particular, demand flexibility by energy-intensive industrial companies can play a key role. By flexibilizing their production processes, industrial companies can contribute to an increased use of variable RES (in the following referred to as Variable Renewable Energy (VRE)) to lower the CO_2 footprint of their products with positive effects on economic competitiveness. Together with other flexibility sources like electric vehicles, the EU can transition to a just, low-carbon society and economy with benefits for all. However, to actually realize these benefits, market design must account for the changing production and consumption characteristics, e.g., the intermittency of VRE.

Starting with current challenges of the energy transition that need to be solved with a future market design in the EU, the whitepaper takes alternative market design options and recent technological developments into account, which are highly intertwined. The whitepaper elaborates on the role of, for instance, flexibility, digital technologies, market design with locational incentives, and possible transition pathways in a European context. The "Clean energy for all Europeans" package offers a new opportunity to deepen the integration of different national electricity systems, whereby Transmission System Operators (TSOs) are required to reserve at least 70% of transmission capacities for cross-border trades from 2025 onwards. The corresponding scarcity of transmission capacities on the national level, however, may aggravate congestion to a critical extent, calling for transformational changes in market design involving, e.g., a redefinition of bidding zones close to the network-node level.

The present whitepaper can be seen as part of a series of whitepapers on electricity market design 2030 - 2050 [14, 15] and continues the analysis of regionally differentiated prices or Locational Marginal Pricing (LMP) as a means to address congestion problems in future VRE-based electricity systems. Thereby, the whitepaper extends the findings of the previous two whitepapers (where in the latter whitepapers, e.g., a detailed discussion of the pros and cons of LMP can be found) and elaborates on the question how LMP could be implemented in one or several European countries and how possible implementation pathways may look like in a coupled European system. Moreover, the whitepaper describes preparatory steps that are necessary for the introduction of LMP, and – at the same time – create advantages for countries under both, a nodal and zonal market design. All in all, the results and outcomes of the whitepaper shall support the market design transition in Europe and, thus, the integration and activation of flexibility potentials to foster a fast reduction of CO_2 emissions through a better use of VRE. Therefore, the whitepaper contributes with concrete policy measures to the overarching vision of a future European electricity market design that bases on low-carbon technologies and enhances welfare and fairness, while ensuring economic competitiveness of Europe.

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Acronyms

ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	automatic Frequency Restoration Reserves
AI	Artificial Intelligence
ATC	Available Transfer Capacities
BRP	Balance Responsible Party
CACM	Capacity Allocation and Congestion Management
CAISO	California Independent System Operator
CBMP	Cross-Border Marginal Price
CEER	Council of European Energy Regulators
CMM	Capacity Management Module
CMOL	Common Merit Order List
DER	Distributed Energy Resource
DLMP	Distribution Locational Marginal Pricing
DLT	Distributed Ledger Technologies
DSO	Distribution System Operator
EBGL	Electricity Balancing Guideline
EBR	Electricity Balancing Regulation
EC	European Commission
EEA	European Economic Area
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
EU	European Union
EU-DSO	European Distribution System Operators
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
EV	Electric Vehicle
FB	Flow-Based
FBMC	Flow-Based Market Coupling
FCR	Frequency Control Reserves
FERC	Federal Energy Regulatory Commission
FfE	Forschungsgesellschaft für Energiewirtschaft mbH
GCT	Gate Closure Time
IAEW	Institute for High Voltage Equipment and Grids, Digitalization and Energy Economics
ICT	Information and Communications Technology
IDA	Intraday Auction

IDC	Intraday Continuous
IEA	International Energy Agency
IGCC	International Grid Control Cooperation
IN	Imbalance Netting
IoT	Internet of Things
IRENA	International Renewable Energy Agency
ISO	Independent System Operator
ISP	Imbalance Settlement Period
JOA	Joint Operating Agreement
KPI	Key Performance Indicator
LMP	Locational Marginal Pricing
LTA	Long-Term Allocation
MARI	Manually Activated Reserves Initiative
mFRR	manual Frequency Restoration Reserves
MIC	Minimum Income Condition
MiFID	Markets in Financial Instruments Directive
minRAM	minimum Remaining Available Margin
MISO	Midcontinent Independent System Operator
ML	Machine Learning
MRLVC	Multi-Region Loose Volume Coupling
MTU	Market Time Unit
NECPs	National Energy and Climate Plans
NEMO	Nominated Electricity Market Operators
NRA	National Regulatory Authority
OFGEM	Office of Gas & Electricity Markets
OPEX	Operational Expenditure
PAB	Paradoxically Accepted Bid
PCC	Point of Common Coupling
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PJM	Pennsylvania-New Jersey-Maryland
PRB	Paradoxically Rejected Bid
PRMIC	Paradoxically Rejected Minimum Income Condition
PTDF	Power Transfer Distribution Factor
PUN	Prezzo Unico Nazionale
PV	Photovoltaic

RAM	Remaining Available Margin
RES	Renewable Energy Sources
RR	Replacement Reserves
RTO	Regional Transmission Organization
SCO	Scalable Complex Order
SDAC	Single Day-Ahead Coupling
SIDC	Single Intraday Coupling
SM	Shipping Module
SO	System Operator
SOB	Shared Order Book
TCM	Terms and Conditions or Methodologies
TERRE	Trans-European Replacement Reserves Exchange
TSO	Transmission System Operator
TTFS	Time To First Solution
UK	United Kingdom
US	United States
VRE	Variable Renewable Energy
WPP	Wind Power Plant
XBID	Cross-Border Intraday Market
ZKP	Zero Knowledge Proofs

1 Introduction

In light of recent efforts to deliver on the European "Green Deal", the EU has launched the "Fit-For-55" package with the aim of fast decarbonizing Europe and making it the first continent worldwide to reach climate neutrality. In this package, the EU sets out a clear pathway to reach climate targets by 2030 (e.g., reducing emissions by at least 55 %, compared to 1990) in a fair, cost effective, and competitive way [53]. The member states have additionally committed themselves to reaching the common goal of climate neutrality by 2050 [53].

One major component of reducing greenhouse gas emissions is promoting a higher share of RES in the European electricity system, whereby RES should make up for about 40 % of the electricity mix by 2030 [53]. Successfully integrating RES in the electricity system, however, is a challenging task, as in particular feed-in by VRE is highly intermittent and dependent on factors like, e.g., time of day, season, and uncertain weather conditions. Moreover, VRE are regionally dispersed and, in most cases, directly connected to the distribution grid. Such intermittency and decentralization makes balancing electricity supply and demand more challenging, leading to grid strain and congestion, e.g., in times of excess feed-in by VRE. To manage congestion, grid operators currently recur to costly measures like, e.g., redispatching conventional (and controllable) power plants or curtailing VRE generation, with total costs amounting to over one billion EUR in 2020 in Germany alone [27].

Hence, to better integrate VRE in the European electricity system and reduce congestion, massive grid reinforcements, e.g., in terms of additional grid capacity and new transmission lines, are necessary. Such infrastructure investments, however, are linked to high costs, strict regulatory requirements, as well as long planning and construction horizons. In addition, grid extensions quite frequently hit resistance from society and face severe acceptance problems, as they interfere with existing infrastructure (e.g., ripping up streets) and nature (e.g., interfering with natural habitats) [122]. As a result, the development of grid infrastructure currently lags behind in most European countries and will most likely not be able to fast and completely solve the growing congestion volumes. Thus, in addition to pure grid infrastructure developments, measures to better manage grid congestion gain importance. Such measures comprise, e.g., the exploitation of flexibility potentials in the electricity system with the aim of flexibly adapting to intermittent VRE feed-in [141, 134]. One such flexibility option is active consumer engagement and demand side flexibility, which refers to adjusting electricity consumption or load, e.g., of large-scale industrial electricity consumers, to the needs of the electricity system [141, 134].

To fully exploit existing flexibility potentials throughout Europe, electricity markets need to create incentives for, e.g., electricity consumers, to provide their flexibility to the market to address both, grid as well as system balancing needs, and invest in flexible technologies. Thereby, generating appropriate market signals for flexibility and reconsidering the current market design in light of the ongoing energy transition constitute important means to speeding up decarbonization. When devising a new market design, the choice of concrete design options needs to be handled with great care, starting from a long-term vision of future European electricity markets. Setting up a clear vision is important, as it helps avoiding the adoption of premature market design solutions that may, ultimately, result in path dependencies and lock-in effects, meaning that switching market design policies (and developed business models or technologies) gets increasingly difficult and costly.

Being part of some kind of series of whitepapers on electricity market design 2030 - 2050 [14, 15], the current whitepaper continues the analysis of regionally differentiated prices or LMP. Against this background, the whitepaper deals with the question of how LMP could be implemented in one or several countries of the coupled European system, and in this way extends the findings of the previous whitepapers (that contain, e.g., a detailed discussion of the pros and cons of LMP). All in all, the present whitepaper gives a short overview of the development of liberalized European electricity markets (Section 2) and identifies current challenges on the way to reaching climate neutrality in Europe (Section 3). The whitepaper proceeds by summarizing different flexibility options (Section 4) and digital technologies (Section 5) that may contribute to overcoming these challenges. Lastly, starting from the current regulatory framework and a long-term perspective of European electricity markets, the whitepaper specifies clear market design options for Europe

(Sections 6 and 7) that help exploiting flexibility potentials and complementary digital technologies on the way to a decarbonized and climate-neutral Europe.

1.1 Methodological approach

In deriving policy implications for the future design of European electricity markets, we proceed by adopting a multi-method approach, starting from researching related literature, conducting co-author workshops, as well as a simulation study to estimate current and future flexibility potentials. Moreover, we conduct qualitative interviews with experts on energy systems from research and practice across Europe. The expert interviews allow to contrast different opinions and ideas from a broad variety of stakeholders in the European energy system like, e.g., grid operators, industrial companies, or intergovernmental organizations, and to draw first conclusions regarding the practical feasibility of our policy implications.

In conducting the interviews, we follow a partly conceptual as well as argumentative deductive analysis [130, 21]. We choose qualitative semi-structured interviews that are guided by a questionnaire containing a set of open questions regarding, e.g., policy-making and regulation, market design, digital technologies or flexibility incentives, as the primary method for data collection [116]. We have interviewed a total of 12 experts in European energy markets and systems from different countries via video calls. In determining the number of interviews, we follow the recommendation in [24] that suggests 11 to 20 interviews, before reaching a saturation point, after which additional interviews only yield limited insights. Also in our case, responses of the interviewed experts converged at 12 interviews to a common set of identified challenges for the energy transition.

The interviews proceed by first giving a short introduction to the research objective and the involved research projects, SynErgie and OneNet. In a second step, the questionnaire, which has been sent to the participants already beforehand, is used to guide through the interview. The questionnaire contains mainly grand tour questions, example questions, and prompts [104]. During the interview, we have slightly adapted the questions to focus on the participants' respective knowledge and expertise [116]. The duration of the interviews ranges from 45 to 90 minutes. All interviews have been audio-recorded as well as transcribed. For the analysis of the transcribed content, we use qualitative content analysis, as recommended in [109]. The resulting transcripts and insights from the interviews serve as an important basis for this whitepaper and the derived policy implications.

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2 The European electricity market at a glance

This section describes the **liberalization of the European electricity market** with focus on the development of network codes and guidelines as well as the involved actors. The European Commission (EC) enhanced the liberalization in the last 25 years. During this time, the EC formed some key organizations, i.e., **European Network of Transmission System Operators for Electricity (ENTSO-E) as permanent representation of the European TSOs, European Union Agency for the Cooperation of Energy Regulators (ACER), and the relatively new European Distribution System Operators (EU-DSO) entity.** The process for developing network codes has been increasingly refined by the EC. Especially with the last energy package, this evolution is mainly characterized by a shift of responsibility from ENTSO-E to ACER, making ACER the central player in network-code development.

2.1 Short history of the European electricity market

Part of the EU vision is a common European market that eliminates trade barriers between Member States. This vision dates back to the founding Treaty of Rome in 1957, the most important amendment to which is the Single European Act of 1986, which requires the adoption of measures to create a single market by December 31, 1992. Starting from 1993, the European internal market went into effect for the 12 Member States at that time. For the European integrated energy sector, however, this date can only be considered a starting point, because the energy sector in most member states was up to the mid-1990s still dominated by vertically integrated utilities with regional or national monopolies. Since then, the EU drove the evolution of the European energy market with four legislative energy packages that led to a liberalization of the energy sector and the fragmentation of the utility monopoly position, visualized in figure 1.

First Package 1996
1996
Directive 96/92/EC concerning common rules for the internal market in electricity

Second Package 2003
2003
Directive 2003/54/EC
Regulation (EC) No 1228/2003

1996

Third Package 2009
2009
Directive 2009/72/EC
Regulation (EC) No 714/2009

2003

Clean Energy Package 2019
2019
Directive (EC) 2019/944
Regulation (EU) 2019/943
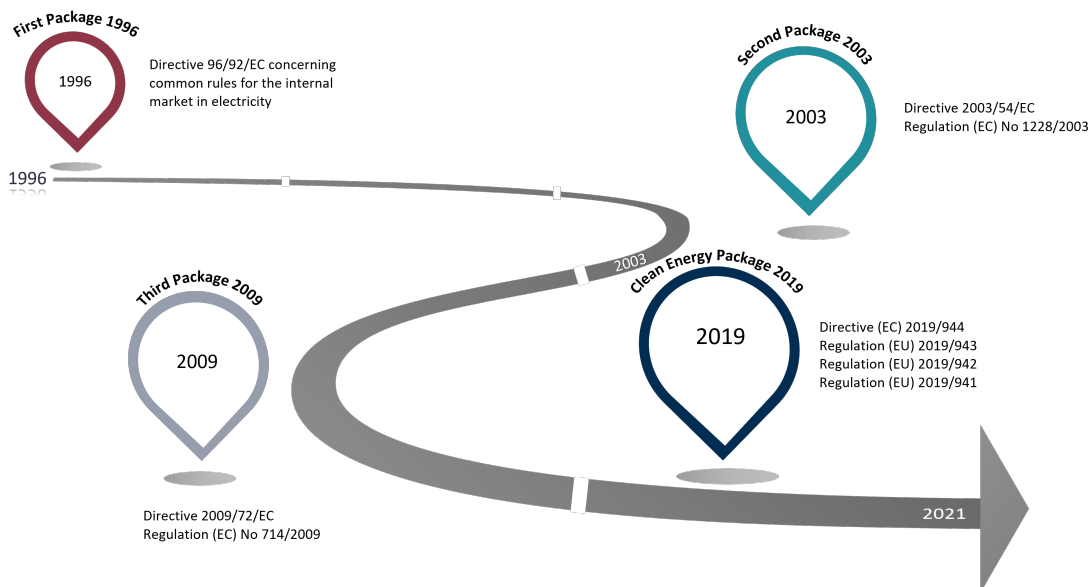Regulation (EU) 2019/942
Regulation (EU) 2019/941

2021

Figure 1: The four energy packages and their corresponding directives and regulation between 1996 and 2020

Each package enhanced the ongoing liberalization process of the energy sector with large impacts on the TSOs and increasing as well as clarifying the responsibilities of national and European regulatory authorities. The first package in 1996 mandated the management and accounting unbundling of the national TSOs, followed by the legal unbundling of the national TSOs with the second package 2003. Therefore, the first two packages gradually increased the independency of the TSOs from generation. The third package in 2009 mandated the creation of ENTSO-E as the head organization of all European TSOs to foster the European vertical integration of system operation by developing network codes, guidelines, and Terms and Conditions or Methodologiess (TCMs), including the monitoring and analysing their implementation. The Clean Energy Package 2019 introduces the establishment of EU-DSO, the corresponding head organization of the European Distribution System Operators (DSOs). EU-DSO will participate in the further development of the grid codes and fostering a close cooperation between DSOs and TSOs. The energy packages fostered the national regulatory bodies by mandating that each Member State needs to create a designated single independent National Regulatory Authority (NRA) at national level. The European NRAs ensure that each member state fulfils its targets for energy markets and implements the relevant EU regulatory policies accordingly. In order to enforce regulations NRAs can impose sanctions on system operators that do not comply with the requirements of the regulatory framework. With the third package 2009, the EU established ACER, the head organization of the European NRAs that has the assignment of producing framework guidelines for the network codes and common market monitoring.

The Clean Energy Package 2019 greatly increased ACER responsibilities, making it officially an EU Agency. The concrete and detailed market rules are developed through the process of creating EU network codes and guidelines including the associated TCMs, as described in Section 2.2. Network codes and guidelines are adopted as regulations by the EC, which are legally binding and, therefore, do not need to be transposed into national law. Network codes and guidelines differ in the degree of detail. In general, network codes are more detailed than guidelines. Guidelines allow for more flexibility and further development during the implementation and transposition into national legislation. During the implementation of guidelines, TSOs together with Nominated Electricity Market Operatorss (NEMOs) elaborate so-called TCMs, which are comprehensive legal texts that define the framework of the guideline. A TCM can address a European, a regional or national scope. Depending on their scope, TCMs need to be approved by all NRAs, a subset of NRAs, or by ACER directly.

Envisioned by the European treaties, framed by the European energy packages, and shaped in more details with network codes, guidelines, and TCMs, the liberalization and further evolution of the European energy markets is an ongoing project as part of forming an integrated market for the EU. A comprehensive description of the evolution of electricity markets in Europe can be found in [110] and [76], which served as a template for this section.

2.2 The development process of network codes and guidelines

The development of network codes and guidelines follows a four-step process which is mandated in (EU) 2019/943 article 59. In step one, the EC drafts a priority list after consulting ENTSO-E, EU-DSO, and "other relevant stakeholders" every three years. In the priority list from 2020, the EC identified two topics: Cybersecurity and Demand-Side Flexibility. Addressing the topic from the priority list, ACER develops framework guidelines after a request from the EC in step two. The framework guidelines provide a clear and well-defined basis for the network codes and guidelines, guaranteeing an efficient functioning of the market. After drafting the initial version of the framework guidelines, ACER consults ENTSO-E, EU-DSO, and other relevant stakeholders to refine the initial version in an open and transparent two-month process. Afterwards, ACER submits the revised framework guidelines to the EC for final acceptance. If the EC accepts the framework guidelines, ENTSO-E is requested to draft a proposal for a network code/guideline on base of the developed framework guidelines in a time frame of maximal 12 month. Afterwards, ENTSO-E submits the drafted network code/guideline to ACER for assessment under consultancy of relevant stakeholders. This assessment is then shared with ENTSO-E. ENTSO-E has defined a standardised development process for their network codes, including the terms under which relevant stakeholders are engaged. If ACER accept the final version of the network/guideline draft, it will submit the draft to the EC with a recommendation for adoption, which start the fourth and last step of the process with initializing the committee procedure for

the formal adoption of the network codes/guidelines. A more detailed description of the implementation of network codes and guidelines can be found in [76], which was the base for this short summary. The detailed drafting process and the following committee procedure allows for further refinements and amendments in case of missing consensus between the involved stakeholders. Important changes in the latest energy package related to the network code/guideline process is the establishment of the new EU-DSO entity with article 52 in (EU) 2019/943 and shifting the responsibility for the final approval process about the submitted draft network codes/guidelines from ENTSO-E to ACER.

3 Challenges in current and future European electricity markets and systems

> The section considers the main challenges in current and future European electricity markets and systems that have been pointed out during the expert interviews. These challenges comprise, among others, the domains of **policy-making and regulation, grid operation and management, digital technologies, financing the energy transition and (better) integrating coupled European electricity markets.** Overall, future European electricity markets and systems need to find a suitable balance between the overarching EU policy landscape and the needs of individual member states, enhance the integration of VRE and flexibility potentials in both, market design and the operation of grid infrastructure, and make use of state-of-the-art digital technologies to allow for, e.g., active consumer participation in electricity markets.

Even though a broad range of legislative packages and initiatives has been implemented by the EU and its member states (see Section 2), some major challenges remain on the way to a climate-neutral European continent. Quite often, these challenges concern in particular stakeholders in the electricity system that are responsible for putting EU guidelines into practice and operating the underlying infrastructure or business models. For that reason, the following section bases upon the insights collected from the interviewed experts in European electricity systems, comprising a broad spectrum of stakeholders involving, e.g., grid operators and utilities, private companies, experts from academia as well as intergovernmental organizations.

During the interviews, the participants have pointed out challenges referring to policy-making and regulation, grid operation and management, the use of digital technologies, finance as well as market design as major impediments to the European energy transition. In the remainder of this section, the identified challenges are described in more detail.

| Challenges in policy-making and regulation |
| Challenges in grid operation and management |
| Challenges concerning digital technologies |
| Challenges in financing the energy transition and (better) integrating coupled European electricity markets |

Figure 2: Challenges pointed out by the interviewed experts in European electricity systems

3.1 Challenges in policy-making and regulation

As outlined previously in Section 2, the EU and its member states have committed to more ambitious climate targets in the recently proposed "Fit-For-55" package. Delivering on these goals in practice, however, is challenging, as it requires a suitable policy framework and clear pathways to reduce emissions and decarbonize the energy system. When devising these pathways and adopting new policies, proposals by the

EC need approval by both the European Parliament and the Council [131]. While iterating policy proposals between different EU institutions is, for sure, a prerequisite of democratic decision-making, consolidating the views of the different member states, e.g., in the European parliament, is a lengthy process. As a result, EU (but also national) regulation frequently lags behind recent developments, e.g., in terms of leveraging flexibility potentials and deploying state-of-the-art technologies like smart meters [102]. While EU policies have indeed been quite instrumental in the last couple of years in pushing forward VRE expansion and their market integration, not all relevant aspects like, for instance, grid management or the deployment of complementary technologies (e.g., storage or digital devices), have been taken into account in the required detail. As a result, EU regulation – in some cases – can only ex-post react to such developments, instead of proactively guiding them. While the proposed "Fit-For-55" package may be a promising step in making EU policies more proactive, the following negotiations will again be quite lengthy, resulting in one more challenge that European policymakers have to overcome.

Changing the role of regulation and actually delivering on common climate goals also demands a strong political willingness to do so. Quite naturally, the efforts needed to achieve climate neutrality differ significantly between member states depending on, e.g., geography, existing grid infrastructure as well as the share of industry. Hence, depending on the anticipated effort, the political willingness to take concrete actions towards climate neutrality may also differ between member states [75]. What is more, due to the different national characteristics, individual decarbonization paths may be required to fit the needs of each member state and comply with the principles of subsidiarity and proportionality (instead of a European "one-size-fits-all" solution). Hence, to foster political acceptance and willingness for change, a European policy framework needs to set the overarching goals (e.g., emission reduction targets), while still leaving room for individual implementation strategies by the member states. Currently, the EU already follows such a subsidiary approach, by laying out a 2050 long-term strategy for climate change [45] and proposing a mid-term strategy in the "Fit-For-55" package [53]. In addition, all member states have to present long- and mid-term National Energy and Climate Plans (NECPs) in which they tailor the EU strategy to the local characteristics [56]. However, NECPs usually focus more on the energy mix of the respective country and choices on technologies like, e.g., electricity generators, rather than on adjusting (national) regulations in light of the EU regulatory framework. Thus, (fully) incorporating EU regulation in national law in a way that is effective and does not conflict with other national regulations is still quite challenging.

Building upon the prior challenge of harmonizing European goals and national regulation, it must be noted that translating EU requirements and directives into national law is not always trivial. This is the case, as EU regulation that focuses on overarching goals is often vague and lacks clear suggestions on how to implement the proposed requirements in national law. While some degree of "vagueness" is indeed desirable to make EU regulation generalizable and individually applicable for member states in line with their local characteristics, vague formulations may also come at the cost of increasing regulatory and planning uncertainties on the national level. Such uncertainties may then affect in particular long-term investment decisions, e.g., with respect to VRE capacities or flexible technologies. Moreover, vague formulations in the EU regulation may also blur individual contributions of the member states to climate neutrality. Even though current EU regulation obliges each member state to devise individual action plans for mitigating climate change (like NECPs) and report their emissions on an annual basis [50], it does not state whether European emission targets are met by the help of "frontrunners" that exceed their targets or in equal shares [57]. It is, thus, challenging to devise EU regulation that creates legal certainty on the national level, e.g., for policy-makers and investors, and avoids possible "freeriding" on member states exceeding their emission targets.

As outlined in this subsection and the remainder of this whitepaper, the transition to climate neutrality demands regulatory adjustments on both, the European and national level. One challenge that is linked to such adjustments is considering possible dependencies and spill-overs between different regulations, e.g., regulations complementary to existing electricity or energy law like the European hydrogen strategy [46] or carbon prices [51]. In that regard, the main challenge lies in identifying possible dependencies, in the first place, and ensuring harmonization of and synergies between the different regulatory frameworks. Moreover, specifically considering the decarbonization of the European electricity system and meeting emission targets, policymakers face the challenge of sticking to a technology-agnostic approach that does not favor

specific decarbonization technologies like, e.g., certain energy carriers or flexibility options, by law [127].

3.2 Challenges in grid operation and management

In general, the energy transition impacts and introduces challenges to power grid operation. The concrete challenges vary from member state to member state and depend heavily on the regional / national situation related to network development, market integration, and cross border connectivity. A main trend of the energy transition is the increasing number of decentralized energy systems (e.g., generation unties, loads, and storage systems), mostly connected to the distribution grid and dominated by a large share of direct current generation units with a variable generation profile. These systems introduce a series of challenges towards grid operation, but also provide the opportunity for new services to the system operators and therefore should be part of a "solution". Increasingly, distributed generation units will replace conventional and mostly fossil-fired large-scale power plants. This development will reduce the inertia with regard to the frequency stability of the European energy system, and thus favour frequency fluctuations. To prevent frequency fluctuations, it will be necessary to control the future energy system with a higher regional granularity and higher resolution. The market-driven efficient integration of distributed flexible energy systems in the distribution grid will play a central role in this respect.

Increasing power generation from fluctuating renewable energy sources such as Photovoltaic (PV) and wind turbines (and also increasing number of new electrical loads like Electric Vehicle (EV) and electrical cooling and heating systems) in the distribution network has an increasing impact on the power grids. On the generation side, volatile renewable energy sources cause electricity to be generated when the sun shines or the wind blows, regardless of whether the electricity generated is currently required. On the consumption side, the probability of load peaks due to, e.g., the simultaneous charging of a large number of EVs or due to an increased demand for thermal comfort, which is covered electrically, increases. These two partially contrary developments will make it necessary in the future for the consumption side to increasingly adapt to the respective generation capacity available. Also in this context, the use of distributed flexible sources could play an important role in the operation of the future energy system.

The aforementioned shift in the generation portfolio and the increasing demand for electrical energy is also causing increasing problems with respect to the transportation of electricity, because regions with large generation capacities may not be the same where large consumption is located. Therefore, electricity is often transported over long distances to the major centers of consumption. Here, the existing grid infrastructure is increasingly reaching its limits leading to congestion problems in the power grid, which need to be mitigated by system operators. One example for these mitigation interventions is called redispatch. If a system operator is forced to activate a redispatch measure to prevent grid congestion, the system operator initiates a reduction of generation in one grid segment and an increase of generation in another grid segment. All involved parties impacted by the redispatch measure will be compensated for their adjustments to their planned operation. The increasing number of such redispatch measures has driven up the operating costs of many electricity network operators massively in recent years.[1] The costs incurred are passed on directly to the end customers, which lead to increasing electricity prices for end customers in the last years.

3.3 Challenges concerning digital technologies

Already today, digital technologies enable a much more fine-grained control of the energy system that is necessary to integrate flexible energy generation and consumption from all sectors with the goal to allow a higher penetration of RES. System operators utilize these technologies to compensate the growing complexity in controlling their systems. The increasing merging of digital control technology and the energy system comes with its very own series of new problems and challenges. During summer 2021, the EC published its action plan on the digitalization of the energy sector with a request for feedback, see Ares(2021)4720847. The EC received various replies on their request for feedback, which provide an interesting overview of the most common challenges in the implementation of the digitalization of the energy sector. The following paragraphs summarize some of the most frequently cited challenges.

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[1]ENTSO-E publishes the costs for congestion management per EU country on ENTSO-E's transparency platform, see `https://transparency.entsoe.eu/`

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An updated European energy market design will enable consumers with progressive access to flexible electrical assets and combined with digital control technologies to actively participate in the new markets, see Section 5. The consumers' interests, hereby, shift from simply consuming electrical energy to a higher need for energy services which will allow them to optimize the use of their flexible assets in order to reduce their energy bills. Consumers' demand for energy services will create new market players who will exchange energy directly with the consumers. This interacting will rely on a robust communication interface between the market actors that will allow to exchange price data and measurement data in real time. Harmonized data models and interfaces will be key to enable an integrated and fully digitized European energy market. The heterogeneous state of the smart meter roll-out throughout Europe may hinder the successful use of a common data exchange model, because some nation states pursue their own non-standard smart meter approaches.

The open access to data with consumers' consent and considering privacy aspects will enable the energy and digital transformation. The electrical supply chain is increasingly characterized by contractual multi-stakeholder relationships, which rely on data exchange and corresponding transactions. The development of energy marketplaces will enable new services, focusing the consumers, on basis of open access to data while respecting consumers' consent and privacy. Data exchange between various stakeholders and market actors will enable horizontal, vertical, and cross-sector synergies. An interoperable data exchange between all stakeholders and actors of the energy market can only be facilitated by standardized and harmonized data models and data interfaces. These standards should be aligned throughout Europe and adapted to the realities of new market models.

The integration of digital technologies in the operation of the energy sector and energy markets significantly increases the requirements in terms of IT security and the protection of critical infrastructure. The security of the power grid's digital operational layer becomes hereby as important as the security of the physical grid. In particular, the increasing number of interconnected digital devices in the power system introduces new risks. The power sector needs to enhance its capability in responding to the new risks. For this, a common European coordinated approach seems to be the best solution.

3.4 Challenges in financing the energy transition and (better) integrating coupled European electricity markets

As outlined in the previous subsections regarding grid infrastructure and digital technologies, considerable investments are necessary to make European electricity systems fit for the energy transition and high shares of VRE. In this context, especially suitable electricity price signals are required that incentivize investments in the *right* technologies, e.g., VRE or demand flexibility, and at the *right* place, e.g., to reduce congestion [34]. Consequently, one main challenge lies in developing a suitable European electricity market design that fast stipulates the required investments for the energy transition and makes them economically profitable for investors, i.e., allows for sufficient returns on investment. For example, recovering investments by TSOs and DSOs in "smart" technologies, e.g., smart grids, is currently quite difficult, as they are classified as Operational Expenditure (OPEX) [106, 107, 95, 44], and, thus, are not considered for interest returns. In that sense, regulation may hinder investments in certain technologies, even if market signals would actually incentivize them. As a result, the challenge lies also in co-developing wholesale market design and network regulation, such that they are mutually beneficial and correspond to the current and future conditions of the electricity system.

One further challenge that has – among others – been named by the interviewed experts is the general redesign of European electricity markets. While market design needs to stipulate investments in the energy transition, as noted before, the challenge goes way beyond investment signals or finance. More precisely, a future-proof electricity market design needs to adequately mirror physical grid constraints [34], in order to ensure market outcomes that can be realized without the need for (costly) ex-post adjustments, e.g., redispatch. This implies, for instance, that market signals need to be provided with such high regional and temporal resolution that they may, indeed, reflect grid realities, e.g., congestion.

Another challenge concerning – in particular – European market design is the interoperability of different (national) markets within the European coupled system. Following the suggestions in Subsection 3.1 on

policy-making and regulation, the EU may provide an overarching framework for electricity markets containing, e.g., overall market goals, and leave the implementation of specific design options to its member states. The subsequent challenge then lies in ensuring interoperability of national markets with possibly different regional or temporal resolutions, and, thus, different pricing mechanisms. In that regard, European-wide standards are required to ensure interoperability of the different markets and a general willingness of the member states to open up markets for inter-zonal, cross-border trades. Thus, European policymakers need to find a suitable balance between detailed regulation and freedom for experimentation with different market designs. Taking the argument one step further, interoperability of electricity markets and systems outside the EU like, e.g., Switzerland or the United Kingdom (UK), also needs to be ensured. When considering flexibility from sector coupling, interoperability with different energy markets like, e.g., gas markets, further plays a crucial role.

4 Flexibility in European electricity systems

This section introduces flexibility resources, divided into the following categories: **Supply-side flexibility, demand-side flexibility, storage flexibility, sector coupling flexibility, and power grid flexibility.** Possible fields of application of flexibility are highlighted in this section, such as **mitigating mismatches in supply and demand induced by volatile feed-in of variable renewable energy plants** and other system services – **frequency control, congestion management, black start capabilities, and voltage control.** In a prototypical simulation the influence of decentralized flexibility resources on the associated potentials for congestion reduction in the transmission grid are analyzed under variation of the market design to coordinate these flexibility resources.

4.1 Definition of flexibility and possible fields of application in electricity systems

As described in Section 3, the increasing penetration of VRE plants yields new volatility and uncertainty [91]. In addition, the electrification of various sectors, i.e. buildings, industry, and transport, means an accelerating penetration of new types of consumers, such as EV or heat pumps, and thus an increase in electricity demand. If not well-planned, the combination of large shares of VRE together with rapid electrification could affect the reliability of the power system [91]. However, the ongoing electrification is not only a challenge, but creates an opportunity at the same time. With appropriate information and communication technology, these new technologies can help to compensate for the volatile characteristics of VRE sources [103].

But what exactly is flexibility? Eurelectric defines flexibility as follows:

> "[...] [F]lexibility is the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. The parameters used to characterise flexibility include the amount of power modulation, the duration, the rate of change, the response time, the location etc." [43, p.5].

Focusing on power systems with high shares of VRE, the International Renewable Energy Agency (IRENA) extends the previously given definition of the International Energy Agency (IEA) (see [89]) as follows:

> "Flexibility is the capability of a power system to cope with the variability and uncertainty that VRE generation introduces into the system in different time scales, from the very short to the long term, avoiding curtailment of VRE and reliably supplying all the demanded energy to customers" [93, p.23].

Flexibility can be used to mitigate mismatches between supply and demand induced by the volatile feed-in of VRE [91]. Furthermore, flexibility is able to provide other system services such as frequency control, congestion management, black start capabilities, and voltage control [70]. To achieve this, flexibility potentials need to be harnessed in all parts of the power system [91]. The following subsections therefore provide an overview of the available technologies for the provision of flexibility, divided into different categories as shown in Figure 3: supply- and demand-side flexibility, storage and sector coupling technologies as a link between those, as well as grid flexibility. In Subsection 4.7 an exemplary simulation is presented, examining the changes of the flexibility usage – focusing on decentralized demand-side flexibility – in response to different market designs.

4.2 Supply-side flexibility

Serving demand is the task of the supply side of the electricity system and can be achieved through energy conversion plants. In the past, this task was mainly performed by thermal power plants and run-of-river power plants in Europe [88].

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Resources with technical flexibility potential

Supply-side flexibility	Demand-side flexibility	Storage flexibility	Sector coupling flexibility	Power grid flexibility

Figure 3: Resources with technical flexibility potential.

The tasks of such thermal power plants include covering base, shoulder, and peak loads. In this context, base load power plants such as nuclear power can only achieve a low degree of flexibility, since changes in their operation must be carried out in compliance with ramps. Such changes are also associated with a high expenditure of time and resources [80].

In contrast, mainly gas or coal-fired plants can adapt to short-term changes in demand. These changes in performance are accompanied by an increase in the degree of wear and tear of an installation [80].

The acceleration of the energy transition leads to an increasing share in the installed capacity of VRE technologies such as wind, solar, hydro, or biomass power plants. These technologies offer the possibility to provide a renewable and environmentally friendly alternative to fossil thermal power plants. However, they also entail fundamental changes in terms of generation costs, flexibility, and the need for redispatch.

Electricity generation from Wind Power Plants (WPPs) and PV is highly dependent on fluctuating and uncertain weather conditions, which leads to a degree of unpredictability. When congestion issues appear in the grid, system operators often resort to VRE curtailment as a mitigation measure [93]. This leads to an increased need for controllable redispatch (changing the deployment schedule of power plants) based on weather fluctuations [144], which experts believe is one of the biggest challenges facing the power system. Nowadays, the missing energy caused by VRE curtailment is mostly provided by conventional thermal power plants with higher greenhouse gas emissions. A possible future approach in this area is to operate intermittent technologies such as WPP and PV at curtailed output to allow positive flexibility, i.e., higher output, when needed [156]. In order to avoid the loss of renewable energy as far as possible, further technologies and concepts for the provision of flexibility are needed – more details on this will be given in the next sections.

Other technologies offering larger flexibility potentials are hydro and biomass power plants, whose advantages include short start-up times [144]. The degree of flexibility is also characterized by the storability of intermediate products, e.g., biomass technologies require local gas storage units to exploit flexibility potentials. In addition, pumped hydro storage power plants or reservoirs are also of increasing interest due to their inherent storage capability. A disadvantage is their dependency on the geographical location and weather conditions as well as restriction of the water level of the reservoir, since this level must be kept in a certain range [144]. The above list of generation technologies is not complete, but it covers the most important future energy conversion plants, which can – at least to some degree – increase flexibility to complement the operation of VRE plants.

4.3   Demand-side flexibility

In the past, flexibility was mainly provided by the supply side [91] and electricity demand was mainly inflexible and was – or still is – in most cases represented by standard load profiles. These profiles are used to describe the aggregated consumption behaviour of different consumer groups, as there was or – in most European countries – is no regular, sufficiently intensive exchange of information between electricity sup-

pliers and consumers [14]. However, to use flexibility on the demand side, an exchange of information is essential and the question arises, whether standard load profiles are still the appropriate tool to represent the energy consumption of end consumers.

Nowadays, flexibility on the demand-side is predominantly provided by large consumers such as industry, which react to price signals from the market [141] and are equipped with the required measuring technologies. These large, controllable loads offered by industry are of significant value due to their enhanced contribution to managing demand [93]. A distinction is made between the ability of a process to increase (negative flexibility) or reduce (positive flexibility) its demand and, vice versa, for generation plants their feed-in in response to external factors such as system price signals or activation. Yet this demand-side flexibility is highly dependent on the underlying production process, with sub-processes such as heating or cooling typically offering higher inherent flexibility potentials than core processes, which are highly important for the quality of the end product [141, 143]. Forschungsgesellschaft für Energiewirtschaft mbH (FfE) has quantified the potentials of negative and positive flexibility, each characterized by the available power and duration, of a wide variety of industrial processes [71]. These potentials are used in the prototypical simulation in Subsection 4.7.

As described above, the ongoing electrification of end-use sectors leads to an increasing penetration of technologies possessing an high inherent flexibility potential such as EV, heat pumps, and other smart appliances. Flexibility in this case means changing load by either increasing, reducing, or shifting it in time [91]. Technically, this is achieved through bidirectional charging, charging management, or the switching off of loads, for example, by using buildings as an inherent heat store.

Providing demand-side flexibility is an effective method which offers an opportunity for consumers to play an active role in grid operation by adjusting their electricity consumption in response to price signals (e.g., market- or grid-serving) or long-term direct-control agreements [93]. The structured coordination of demand-side flexibility, consisting of loads of various sizes, from washing machines to large industrial consumers connected to the low- and medium voltage distribution grids, to meet expected response rates or capacity reduction targets, is one of the challenges of demand response [93]. For that purpose, the participation of aggregators is encouraged by experts in the field of demand-side flexibility and also already enshrined in the European law (see [63]). Corresponding aggregated pools often contain a mix of different types of demand, as well as storage and flexible generation, to maximize the ability of the aggregated pool for the provision of flexibility to the system and the resulting revenues [93].

Another challenge, which needs to be overcome, is the integration of customers and incentivizing the provision of flexibility so that customers' use patterns are positively influenced to better match supply [92]. As a first step, the EU has initiated the roll-out of smart meters in the Clean Energy Package to identify flexibility potential [67]. According to experts, the introduction of further Information and Communications Technology (ICT) is necessary to make these potentials usable in the future. The developments in the area of digitalization are therefore discussed in Section 5.

4.4 Storage flexibility

Storages enable the (partly) decoupling of supply and demand from each other [149], which experts regard as the biggest advantage of such technologies. This is achieved by shifting energy over a range of time. Other conceivable tasks for storage can be voltage maintenance and the provision of control reserve [151].

A variety of different storage options exists: electrochemical, mechanical, potential, thermal, or electromagnetic [149, 151]. Each of these storage technologies is characterized by either its ability to absorb or release energy (specific power in W/kg) or its ability to store energy (specific energy in Wh/kg) [149]. A comprehensive overview of the current state of storage technologies can be found in [129], where a strong increase in capacity in the field of electrochemical storages is predicted.

Batteries or electrochemical storage devices provide energy by converting chemical energy into electrical energy [149]. These storage technologies are particularly interesting due to their high efficiency compared to other electrical storage technologies [98]. The main disadvantage of these technologies, preventing a

far-reaching commercial use, is the high initial cost, which is expected to decrease in the future due to the increased demand especially through the electrification of the transport sector [128].

As a result of increasing sector coupling, other storage technologies are also gaining an increasingly important role. A more established concept is the concentration of solar energy, which is used to melt salt using the generated heat in order to temporarily store the thermal energy in tanks [74, 149]. The heat can be subsequently converted back to steam and then to electricity. The heat can be pre-produced and shifted to areas with high demand and low generation with the help of latent storage. This can significantly increase the efficiency of generation plants and allow plants to be sized smaller.

4.5 Sector-coupling flexibility

Some sector-coupling technologies such as EV and heat pumps have already been addressed in the demand-side flexibility subsection above (see Subsection 4.3). Therefore, the focus in this subsection is on larger assets in the field of Power-to-X.

Most of the previously mentioned technologies, including power-to-heat (e.g., heat pumps), are mainly suitable for providing short-term flexibility. Power-to-gas, including the generation of green hydrogen by electrolyzers, is also suitable for balancing long-term seasonal fluctuations, as these technologies offer both positive and negative flexibility. This is achieved through the possibility of storing surplus energy in the form of other energy carriers. In the event of VRE overproduction, gas can be produced and used at later times, for example, to provide electricity and heat (see [93, 14]). The advantage here is that gas is easier to store than electricity. In addition, for example old slag caverns can be used for storing hydrogen.

4.6 Power-grid flexibility

Grid flexibility, both on the transmission and distribution level, acts as a link between the other flexibility options. If grid flexibility is too low, it can be a limiting factor for other flexibility providers due to congestion issues [93]. Grid flexibility on the transmission level includes the existence of a robust transmission network to balance supply and demand over large areas, as well as cross-border interconnections to enable the exchange of electricity/flexibility across national or other jurisdictional borders, provided the market allows for it. One way to increase grid flexibility is grid expansion that, however, is very costly, faces long construction times, and is often associated with public resistance.

One way to reduce the required grid expansion is to use the flexibility resources mentioned before in the previous sections. The least cumbersome usable resources are often electrical storage systems, which can be placed in a way that they support the grid. The storage units can be used to smooth the electrical load in the grid [120]. This is described in Subsection 4.4.

Another way to reduce grid expansion requires advanced controls to improve communication between grid elements, enabling, for example, automatic control of generators, automatic activation of demand response, or advanced power flow control [93]. These tools are already in use at the transmission grid level. According to experts in the fields of smart grids and digitization, this is an important innovation, especially in the distribution grid. Nowadays, the network status in distribution networks is often unknown and the networks cannot be used efficiently.

In addition, the expansion of VRE plants, especially PV, is mainly taking place in distribution grids, which is leading to a change in the classic energy system. This change is characterized by the fact that energy no longer only flows from higher to lower voltage levels, but in the future there will be a bidirectional exchange between voltage levels [154]. This near-load generation enables and requires flexible technologies to adapt to changing requirements [78].

4.7 Prototypical simulations of flexibility potentials

The objective of our exemplary simulation is to analyze the influence of different market designs on flexibility usage. The focus of the simulation is on decentralized flexibilites, because many flexibility resources are

located on the distribution-grid level [78]. To incentivize flexibility usage, two different market-design alternatives will be considered in the simulation of two exemplary regions in Germany. Market-design alternative one refers to the status quo in Germany. The end users receive a constant price signal for their electricity procurement. In the second alternative, end users see temporally and locally variable prices. These price time series include node-specific costs reflecting grid load and congestion in the transmission grid. How these prices are determined is explained in more detail in subsubsection 4.7.4. In addition to the flexibility usage, the impact on the higher grid level is also analyzed.

4.7.1 Brief model description

The simulation model determines the optimal usage of flexible technologies of a distribution grid region under one node of the transmission grid, while minimizing each participants operating costs (see Fig. 4). Technical options and restrictions of VRE are considered, as well as the obligation to cover electricity and heat demand. The financial impact of self-consumption and subsidization of VRE are also included. This is achieved by mapping each participant on a building-by-building basis, taking into account detailed modelling of the energy flows, while abstracting the distribution grid. A distinction is made between avoided costs (due to self-consumption) and conventional power exchange (full price payment to the utility). For a detailed explanation of the model we refer to [155].

Figure 4: Input-output overview for the simulation framework.

Each participant in the study corresponds to either a building or an energy conversion facility, which can be described by the registry database [155]. The registry database includes stochastic profiles of the building stock in Germany, including energy demand and typical technology portfolios based on socio-economic distributions. Electrical and thermal demand profiles are considered as minimum load restrictions, while driving profiles of EVs have to be met. The flexibility of each technology results from technical characteristics such as installed capacity, power gradients, or mobility restrictions in case of EVs. Price signals for participants include energy costs, grid fees depending on the assumed market design as well as regulatory

price components such as taxes and duties.

The model is based on a linear formulation, which requires an approximation of non-linear constraints, e.g., charging curves of batteries. As a result of the optimization, the model provides operation schedules for each participant's technologies.

4.7.2 Key performance indicator

The results of the simulation model serve as the basis for calculating the Key Performance Indicator (KPI), which quantifies the impact of the flexibility use in the model region on the transmission grid. The price signals from the transmission grid reflect the need to increase or decrease the power at the Point of Common Coupling (PCC) to avoid grid congestion in the transmission grid. The flexibility use under variation of price time series, determined through different market designs, is evaluated, therefore it can be assumed that the distribution grid is congestion-free.

From the perspective of the distributed energy system, a low price would signal the need to draw more energy from the higher voltage level. The opposite is the case with high prices. To calculate the energy at the PCC, the sum of fluctuating generation P_{gen}^t is subtracted from the amount of energy consumed P_{con}^t, resulting in the residual load P_{PCC}^t at these nodes: $P_{\mathsf{PCC}}^t = P_{\mathsf{gen.}}^t - P_{\mathsf{con.}}^t$.

4.7.3 Model regions

The simulation tool can be applied to different regions for a multi-regional evaluation of distribution grids, provided that the necessary input data is available. The selection of the regions is based on a systematic approach, which is described in [155], in order to consider the broadest possible range of participants. In this case, two exemplary model regions in Germany are simulated, one located in northern and the other one in southern Germany to represent different conditions. The energy scenario used is based on the assumptions of a European energy system in 2035, in which Germany has completed the coal phase-out [113]. The installed capacities for PVs and WPPs are taken from Scenario B of the German Grid Development Plan 2019 [1]. Corresponding decentralized energy systems are derived from the overall energy scenario. The studied buildings and facilities are VRE plants, prosumers, and end-users at the medium and low voltage level below the same substation. The regions differ in their ratio of generation to demand and the share of flexible technologies, e.g., EVs is varied for each region. Table 5 shows the main characteristics of the two regions and the variations used in this case study.

Figure 5: Overview of exemplary regions based on [155].

4.7.4 Price time series

Additionally, it is necessary to know the prices of electricity purchase and consumption. In the composition of prices, the different sectors of end users (households, industry and commerce, trade and services) and the annual energy consumption were taken into account [27]. For this case study, two different market designs are compared regarding the impact on flexibility usage. The first alternative examined represents the status quo in Germany: End users purchase energy at a constant price throughout the year. In the following, this is referred to as constant prices.

To determine the prices of the second alternative, a redispatch simulation for Europe is carried out by Institute for High Voltage Equipment and Grids, Digitalization and Energy Economics (IAEW) [2] to determine node-specific costs of congestion elimination in the transmission grid, which are used as flexible price time series seen by the end users in the simulation. This is referred to as flexible prices in the following. The basis of the redispatch simulation is the year 2035 on an hourly basis assuming a day-ahead trading horizon.

4.7.5 Exemplary results

The evaluation of the flexibility potential is carried out by assessing the load at the PCC on the basis of two example regions under variation of the available flexibility options and the market design. One year is examined in hourly resolution. The results are used to determine the residual load at the PCC.

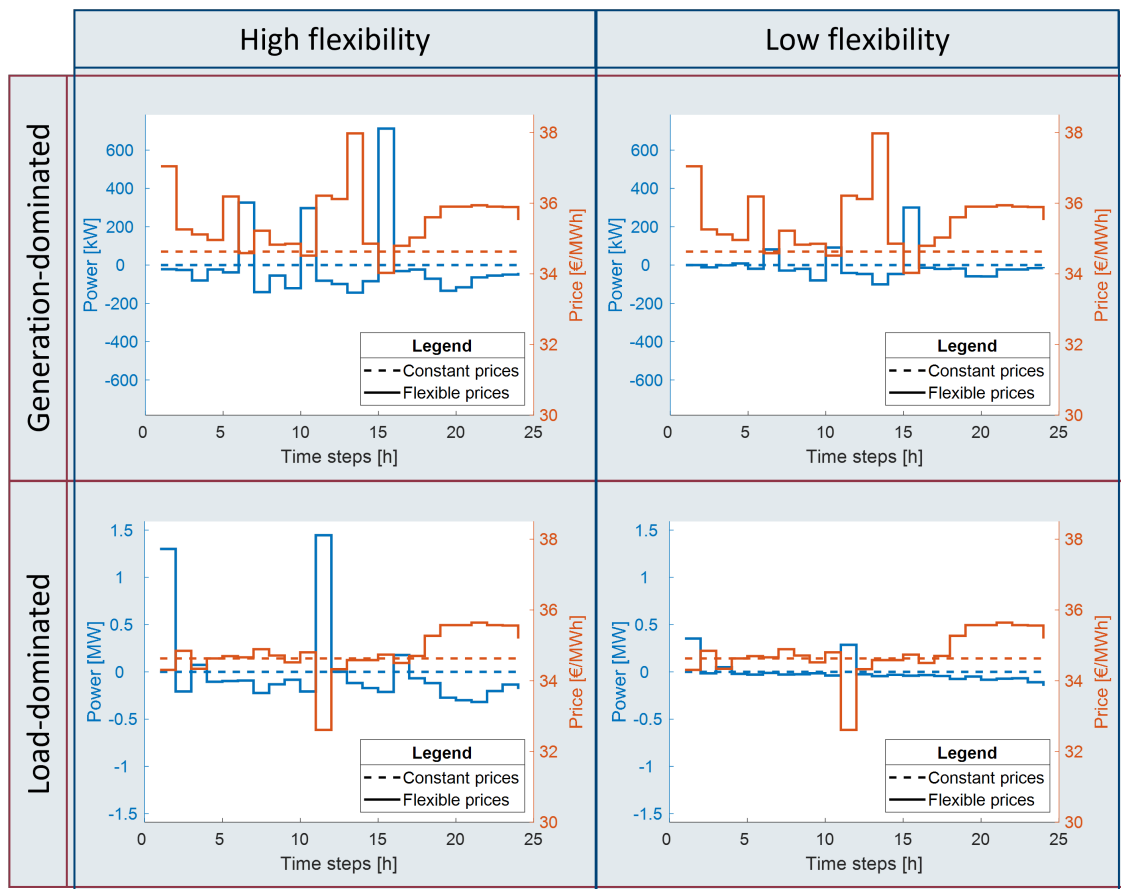## Flexibility potentials for different market designs

Figure 6: Power difference at the grid transfer point for different market designs

In the benchmark case "constant prices", the power difference is defined as zero (see Fig.6, dashed line). In addition, the difference in the residual load for the constant prices case is shown subtracted from the flexible prices case (solid line). This differences reflects the utilized flexibility under the reference prices. The average prices over one year for energy procurement are shown on the right axis of the figure (design scheme equal to the left axis). The results of the calculation are shown as an example for one day in matrix form, broken down by regions and their variations. The calculation per market design can be seen within a matrix element.

Across all four results, it can be seen that price changes can lead to an increase / decrease in load at the PCC, which is available as positive and negative flexibility. The system behaviour is influenced in a way that in times with a high flexibility price, e.g., in times with high VRE generation leading to grid congestion, the demand at the PCC is reduced and vice versa. If less flexibility is available to the system, the influence of the price change on the load is reduced (see right results). Furthermore, it can be seen that constant prices set lower incentives to use generated electrical energy locally. A high share of inflexible load or a low flexibility potential reduces the influence of price changes on the power difference at the rid transfer point, as can be seen from the relatively low deviations at constant prices. Over the entire period under consideration, it can be determined that the load is shifted over time and the total amount of energy consumed remains constant. The combination of a grid with high flexibility potential and a market design that provides incentives for the smart use of flexibility leads to a variation in procurement (load shifting) that can serve the system.

4.7.6   Discussion of flexibility usage and coordination

In summary, this simulation was able to establish the prevalence of a technical demand-side flexibility potential and the sensitivity of the flexibility use to external variable price signals at the distribution grid level. The capability of flexible technologies to respond to monetary incentives can support the transmission grid to reduce congestion.

In reality, the usable flexibility, summarized by the term available operational flexibility, is restricted by technical conditions and the controllability of the assets, the regulatory framework, and the market environment [93], which is shown in Figure 7. The limitations due to the lack of controllability of flexible assets and possible solutions through advancing digitalization in this field are addressed in Section 5. Furthermore, the market design has to be designed such that flexibility can be utilized efficiently and the available technical potential can be exploited. The regulatory framework should also support this. Sections 6 and 7 therefore discuss possible changes of the electricity market design and resulting policy implications and necessary adjustments of the regulatory framework.

For future studies, the questions remain open as to how the flexibility potential can be coordinated appropriately regarding the interactions between decentralized and centralized flexibility and which regulatory hurdles must be overcome for its fulfilment.
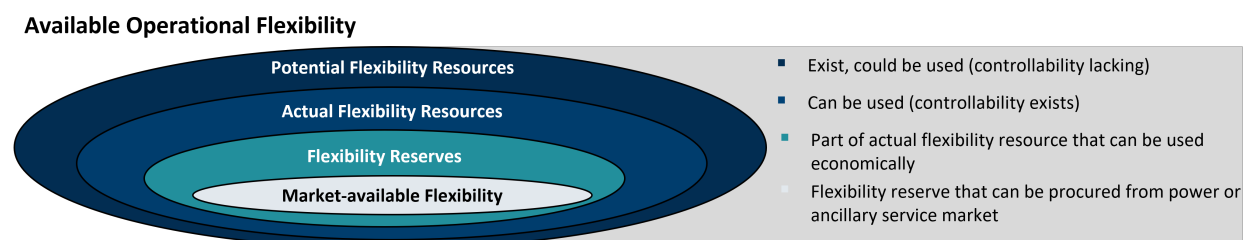

Figure 7: Available operational flexibility based on [152].

5   Possibilities of the digital transformation for European electricity systems

> Digital technologies serve as key "enablers" in **facilitating information exchange** regarding, e.g., the availability and use of flexibility potentials, in current and future European electricity markets and systems. Moreover, digital technologies may contribute to the efficient operation of electricity markets by enabling the **participation of more market players** like, e.g., (small-scale) electricity consumers. Lastly, digital technologies may help addressing questions regarding market design and incentive schemes, by enabling enhanced market **monitoring and the continued (re-)evaluation of market design characteristics**.

Digital technologies serve as key enablers of a deep(er) integration of European electricity markets and systems, as they allow for interlinked flows of different energy carriers (i.e., sector coupling), interconnections of short- and long-term energy markets, and provide the necessary data to match supply and demand at a more disaggregated level and closer to real time [52]. Hence, in its EU strategy for energy system integration [52] as well as digital targets for 2030 [54], the EU emphasizes the important role of digitization in providing economic growth and worldwide technological leadership in the energy sector, also including leadership in reaching climate neutrality. To fully use the potential of digital technologies in decarbonizing European electricity markets and systems, it is important to understand 1) where digital technologies may support communication of previously un- or poorly connected actors (e.g., in terms of grid management and usage of flexibility), 2) how digital technologies may facilitate participation in electricity markets by decentralized market actors (e.g., distributed energy resources or small electricity consumers) and 3) how digital technologies may ensure the well-functioning of future (interconnected) electricity markets, e.g., in terms of market monitoring and detection of malicious behavior.

5.1   Digital technologies as "enabler" of enhanced communication in European electricity markets and systems

As outlined in the previous section (Section 4), flexibility is a key element in decarbonizing European electricity markets and systems, as demand-side flexibility may, for example, reduce the need to activate CO_2-intensive power plants as back-up generation. Thus, in future, closely interconnected European electricity systems, flexibility needs, e.g., for congestion management, and available flexibility options, e.g., demand side flexibility, should be aligned to ensure that flexibility is used at the *right* time and at the *right* place. In aligning flexibility needs and available options, fast and direct communication between flexibility users, e.g., grid and system operators, and flexibility providers, e.g., energy-intensive industrial companies, plays a crucial role. Taking advantage of digital technologies allows to facilitate such communication also in complex multilateral environments and close to real time, involving more and more decentralized actors and flexibility products with high temporal resolution. More precisely, digital technologies may assist the communication between a high number of small-scale electricity consumers and grid operators and, thus, facilitate flexibility usage also on lower grid levels, corresponding to the new requirements of VRE-based European electricity systems. Besides aligning flexibility usage and provision, communication among grid operators also plays a crucial role in making the "best" use of flexibility and foster VRE integration over all grid levels. For instance, swift communication among grid operators like TSOs and DSOs ensures that flexibility is used where it is most needed, e.g., for congestion management, and helps avoiding possible side-effects on up- or downstream grids or grids in neighbouring countries. As a result, digital technologies contribute to enhanced communication in the electricity system and the various actors involved, laying the basis for future-proof and interconnected European electricity systems with high shares of VRE.
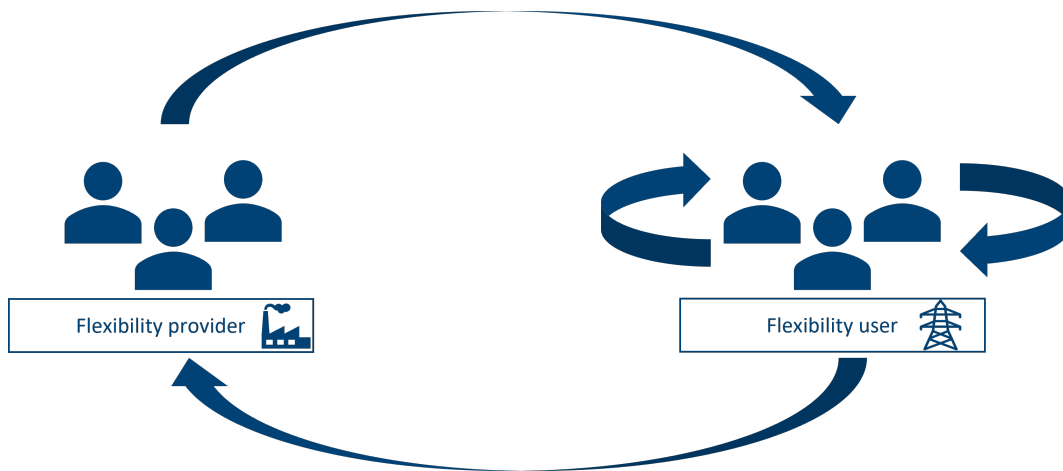
Figure 8: Digital technologies facilitate communication in electricity systems, e.g., for flexibility usage

5.1.1 Communication between flexibility providers and users

Considering communication between flexibility providers and users, digital technologies that speed up communication in the form of automated data exchange may help identifying flexibility needs with higher temporal resolution, e.g., close to real time. Focusing on demand side flexibility, as one flexibility option, communication standards and data models for demand response are specific technology examples that facilitate such automation. More specifically, automated demand response consists of fully automated signaling from a utility, e.g., TSOs, DSOs or Independent System Operators (ISOs), and provide automated connectivity to customer control systems and flexible electronic devices [139, 3]. To ensure interoperability of the different entities or utilities involved in automated demand response, communication standards like, e.g, OpenADR in the United States (US) [22] or the energy flexibility data model for industrial companies [132, 77], may be developed and rolled-out among flexibility providers and users also in the EU [97]. Establishing European-wide communication standards for demand response would also help more easily complying with national electricity market regulations, especially when using cross-border flexibility [97]. Moreover, common communication standards may also facilitate the use of digital platform technologies for flexibility allocation. Platform technologies in this case refer, for instance, to administrative flexibility coordination platforms that facilitate data exchange between flexibility providers and users and allocate flexibility in a centralized cost-based manner [73]. Further examples of platform technologies relate to more market-based applications like, e.g., platform intermediaries that help procuring flexibility services through established markets or flexibility trading platforms that facilitate flexibility auctions as well as market clearing and billing services [73]. In addition to communication standards and platforms, digital identities and certification technologies that are based on Distributed Ledger Technologies (DLT), e.g., blockchain, or Zero Knowledge Proofs (ZKP) may be used to verify the identity of the communicating parties, their market role as well as their respective flexibility offers or needs [94]. In that regard, digital identities and certification technologies may ensure that flexible capacities offered may indeed be contracted or that contracted flexibility is used to manage (verified) congestion.

5.1.2 Communication among flexibility users

Considering communication among flexibility users, digital platform technologies provide an important means to facilitate communication, e.g., between European TSOs and DSOs. In doing so, platform technologies may grant TSOs and DSOs equal access to real-time information on the respective grid situation, e.g., in terms of VRE feed-in, and load profiles of electricity consumers connected to the grid [73]. Quite generally, such communication platforms can be managed in a centralized or decentralized manner [90]. A centralized "data hub" is usually managed by system operators or a regulated third-party, who ensures data integrity and non-discriminatory data access. Conversely, a regional or decentralized platform is managed by the

local DSO, ensuring data integrity and system security. Several European countries like, e.g., Finland and Sweden, are planning to introduce communication platforms or data hubs, while Belgium, Denmark, and Norway already have platforms in operation [90]. In addition to platform technologies, also Internet of Things (IoT), Artificial Intelligence (AI), and Big Data are critical to making the exchange of information and decision-making processes between European TSOs and DSOs as fast and efficient as possible [90].

5.2 Digital technologies as "enabler" of European electricity market participation

When transitioning to a decarbonized European electricity system, policymakers on the EU level have acknowledged that this transition needs to be "consumer centred" [47]. Following the paradigm of "putting consumers at the heart of the energy market", the EC states that "[Fully integrating industrial, commercial and residential consumers into the energy system] even allows consumers to benefit from price fluctuations and to earn money through participation in the market. Activating consumer participation is therefore a prerequisite for managing the energy transition successfully and in a cost-effective way." [49]. In empowering consumers' participation in electricity markets, digital technologies play a fundamental role, namely through granting enhanced access to market data and making demand side flexibility available to grid and system operators in a complex and multinational environment, like the EU.

Digital technologies that facilitate active market participation by electricity consumers or hybrid "prosumers" are, e.g., DLT or ZKP [36]. Currently, market transactions of electricity consumers – especially on lower grid levels – are facilitated by third parties, e.g., aggregators, or electricity suppliers, whose main task is to centrally compile and coordinate information of decentralized consumption and generation units. By making use of DLT or ZKP, decentralized electricity consumers may become active and participate in different electricity markets also without the help of such intermediaries [36]. This is the case, as in particular ZKP provide a privacy preserving alternative for disclosing and verifying consumer identities and, therefore, also account for changing market roles like hybrid prosumers that simultaneously provide and procure electricity on different markets [32]. Analogously, ZKP may also foster the onboarding of electric appliances, like heat pumps or IoT devices, on electricity markets by assigning machine identities [32]. In that sense, electronic appliances or consumer devices like, e.g., industrial machines or household electronics, may automatically connect to electricity markets and purchase electricity based on market signals (buy electricity when prices are low and vice versa) [85, 112]. Here, automated electronic devices may fast change between different markets and market roles, as they are constantly pending on recent market and price developments. What is more, besides verifying (machine) identities and market roles, ZKP may also be used to verify the traded products. This is of particular importance when considering flexibility products, e.g., on balancing power markets, whereby market participants need to credibly prove the actual availability of their flexible capacities. Besides opening up existing marketplaces like those for wholesale electricity or balancing power, electricity consumers may also "become the market" and create new trading opportunities, by using ZKP or blockchain technologies to facilitate peer-to-peer electricity trading and transactions over micro-grids [36, 105, 30].

Actively participating in electricity markets, however, is a challenging task, as complexity increases with the number of market participants and transactions, especially in a coupled and highly interdependent electricity system like the EU. Thus, besides technologies that empower market access (like blockchain or IoT), electricity consumers may additionally make use of AI applications to aggregate market data to higher granularity and use it for decision support. Even if electricity procurement is fully automated and IoT devices act on behalf of humans, AI may be used to generate more accurate forecasts of market developments, e.g., electricity prices, and enable enhanced performance of IoT devices [87]. Also, automated IoT devices need to adapt to each individual consumer, by learning their behavioral patterns and habits in electricity consumption by the means of AI [87].

Summing up, digital technologies may induce mostly passive electricity consumers, e.g., small-scale household consumers, to become active in electricity markets. In this context, digital technologies, e.g., mobile apps using smart meter data, can also make the benefits of active market participation (e.g., by providing flexibility to the market) more transparent for players like households [87]. Building upon the previous notions, digital technologies may also "nudge" electricity consumers to become active market participants, e.g., by displaying savings in electricity costs that can be obtained by more flexible and, thus, active electric-

ity procurement [150]. Abstracting from flexibility, e.g., the proof of how electricity is ultimately *used*, digital technologies may also facilitate the proof of where the consumed electricity *originates* [94]. Thus, electricity consumers may not only become active in electricity markets for marketing their flexibility, but also for reducing their carbon footprint and carbon volumes. To facilitate such incentive-based management of CO_2 and electricity consumption, information on carbon emissions needs to be provided with high temporal and spatial resolution and in a verifiable manner, e.g., by the means of digital carbon certificates [94]. Thus, future research may address the open question of how digital technologies may serve as a "quality indicator" for electricity in terms of CO_2 emissions and make carbon-related consequences of electricity consumption transparent with the highest possible granularity [94].

5.3 Digital technologies as "enabler" of monitoring the well-functioning of European electricity markets

In coupled and highly interdependent electricity markets, like the EU, market monitoring plays a fundamental role in ensuring the well-functioning of current and future markets. Even though, some national regulatory authorities, like the Federal Network Agency and the Federal Cartel Office in Germany, tightly monitor national electricity markets, similar monitoring is also required on the European level for coupled electricity markets and cross-border trades. In course of the Third Energy Package, ACER has been endowed with the tasks and competencies of monitoring the internal markets for electricity and gas [65]. Making use of digital technologies for market monitoring gets increasingly important, as European markets get more integrated, decentralized, and digitized. To further underline this point, with the European strive for more active consumer engagement, electricity markets inherently get more complex and allow for participation of digital "black box" trading agents like, e.g., IoT devices.

In that sense, digital technologies on the side of European market authorities may significantly contribute to detecting malicious market behavior (e.g., abuse of a dominant market position) that is not in compliance with current EU regulation. For instance, AI technologies such as Machine Learning (ML) algorithms may be used to recognize patterns and anomalies in the behavior of market participants. Such patterns refer, e.g., to unlawful alignments of market behavior among two or more competitors with the aim of reaping higher profits [135]. It is noteworthy that such "collusive" behavior may also occur among digital devices like, e.g., IoT, that mutually learn the profitability of circumventing competition, by aligning bids or procurement decisions. In order to detect deviations from competitive baseline behavior (or profits), however, computing a competitive counterfactual (i.e., a solution with "perfect competition") is essential. In finding the competitive baseline, digital twin technologies may be a promising solution, as they allow to better understand the characteristics (e.g., load profiles or cost structures) and preferences of their physical counterpart [13]. Hence, digital twins may be used to investigate the behavior of market participants in market simulations or digital "sandboxes" in the absence of anti-competitive distortions. Moreover, the comprehensive roll-out of DLT may make the need for market monitoring increasingly obsolete, as it facilitates ex-ante control of market transactions (e.g., via certification) and enables monitoring of these transactions by all users (without the help of a central market authority) [84].

Lastly, market monitoring is also essential for evaluating the quality and well-functioning of the current or future European electricity market design, e.g., with respect to its economic efficiency and incentive compatibility. In light of ongoing developments regarding the energy transition and the way to climate neutrality, e.g., in terms of increasing VRE feed-in, the European market design needs to be regularly re-evaluated. Monitoring the behavior of market participants and the corresponding market outcomes allows to draw conclusions with respect to the underlying market incentives generated through market design. To perform market analyses like the EU's gas and electricity market report [68] and the corresponding market evaluations with higher speed and accuracy, digital technologies like, e.g., high performance computing, may be used. By recurring to high performance computing, market analyses can be carried out in finer granularity, taking into account the different designs and peculiarities of interconnected European markets and their participants, ranging from large-scale production and consumption units to decentralized household or storage devices. Hence, high performance computing allows to analyze market structures and incentives in complex (multinational) environments, leading to more detailed evaluations of the underlying market design (and its possible drawbacks).

6 Market design options for a climate-neutral Europe

In this section, it is presented that the **transition to nodal pricing (or LMP)** is one way of using transmission capacities more efficiently and better integrating VRE in the electricity system. Since a Pan-European move to nodal pricing requires significant regulatory and structural changes to electricity markets, it is more realistic that first individual zones or member states undertake such a transition. This raises the question of how a **co-existence of different market designs** in the coupled European electricity system can be organized. Possible alternatives discussed in this whitepaper refer to, **e.g., sequential, hybrid or full nodal market clearing,** whereby the first two alternatives seem most likely in case of a stepwise transition to nodal pricing that starts with individual member states or pricing zones, before introducing nodal pricing across Europe. To prepare for the market design transition across Europe, the **implementation of a shadow solver** that clears the market and computes nodal prices in parallel to the current (zonal) solution is advisable.

6.1 Relevant policy landscape

Quite recently, electricity prices have reached an unprecedented high all across Europe, by almost quadrupling their price level of the previous year (see, e.g., [26] for the development of prices in Germany). On the contrary, during 2020 and earlier this year, European countries have been facing many hours with very low or even negative electricity prices [26]. Following these extreme price developments, electricity prices form a key part of the political agenda in many European countries and also in the EU [10]. In fact, the EC has recently published a communication on energy prices to assist member states in tackling the exceptional price developments in a coordinated and harmonized manner [48]. In the communication, the EC proposes a "toolbox" that the EU and its member states may use to address the immediate impact of price increases (short-term measures), and to further strengthen resilience against future shocks (medium-term measures). While the proposed short-term measures comprise, e.g., emergency income support and temporary, targeted reductions in tax rates for vulnerable households, medium-term measures aim at (fundamentally) transforming European electricity markets and systems, as such transformation provides "[...] the best insurance against price shocks in the future" [48]. In transforming and decarbonizing the European energy system, the EC names market design as one important medium-term measure and emphasizes the need to further study the benefits and drawbacks of the existing European electricity market design [48].

Even before the recent discussion on exceptional price developments has started, market design has been named as one important pillar of the energy transition in the 2019 "Clean energy for all Europeans" package [67]. Thereby, the "Clean energy for all Europeans" package targets at coordinating and harmonizing important parts of European electricity markets to reach fast and effective decarbonization – by making European electricity markets more flexible, more market-based, and better suited to integrate large shares of RES [67]. Also, the package sets out new laws for electricity markets, risk preparedness, and a stronger role of ACER, as an important coordinating body [67]. Quite recently, in addition to the "Clean energy for all Europeans" package the "Fit for 55" package has been proposed, which emphasizes the EU's position as leading the way in the global fight against climate change and sets out more ambitious climate targets [53]. Hence, a combination of recent European reports, proposals, and legislative packages – like the "Clean energy for all Europeans" and the "Fit for 55" package – shape the policy landscape for European-wide decarbonization and a joint energy transition. In conducting the energy transition and delivering on climate targets, market design plays a crucial role and needs to be reconsidered in light of current EU regulation and the overarching policy landscape. Reconsidering European market design, however, demands European-wide coordination and, at the same time, room for experimentation with individual market design options that fit the needs of each member state.

One specific market design option that is already tried and tested on a national (and international) level is the (re-)definition of bidding zones, e.g., in the form of bidding zone reviews. The idea is to choose bidding zones such that the electricity price differences between zones reflect grid scarcities and congestion.

More precisely, bidding zones may involve higher regional granularity of prices to adequately reflect grid congestion and incentivize flexibility provision and investments where they are most needed. In light of the 2019 "Clean energy for all Europeans" package and the corresponding EU regulation, a redefinition of bidding zones becomes increasingly relevant for all member states, as TSOs are obliged to reserve at least 70 % of transmission capacities for cross-border trades from 2025 onward [65, 64]. If these transmission capacities are not fully needed for international trades, they may for sure be also used on the national level to reduce congestion and the need for redispatch. However, since there is no simultaneous consideration of national and international congestion, e.g., in the same algorithm, some sort of ex-ante prioritization needs to take place [35]. In that sense, for 70 % of the available transmission capacities, international or cross-zonal trades are granted priority. As a consequence, transmission capacities that are exclusively available for national electricity flows get increasingly scarce and may aggravate congestion to a critical extent. Considering these developments and the 70 % target entering into force in 2025, transformational changes in market design involving, possibly, a redefinition of bidding zones close to the network-node level or a transition to LMP become more imminent. In addition, congestion becomes increasingly unpredictable as the share of VRE, whose feed-in is affected by uncertain weather conditions, increases. As we elaborate in what follows, a "nodal" market design (or LMP) may effectively manage grid congestion, by (fully) mirroring physical grid restrictions and scarcities in time- and location-specific electricity prices. Hence, transitioning to LMP may facilitate improved congestion management, e.g., on the local level, also allowing for cross-border or interzonal trades.

However, when experimenting with new market designs, not only potential impacts on domestic markets need to be carefully taken into account, but also impacts on neighboring countries as well as coupled European electricity markets. Also, it needs to be clarified, to which extent changes in electricity market design are compatible with the overarching EU policy landscape and regulation. To further investigate the conditions under which transformational changes in market design, e.g., LMP, may be beneficial for single countries, but also for the EU as a whole, this section first weighs pros and cons of nodal pricing in the light of coupled European electricity markets and in comparison to current zonal pricing. Second, it describes current developments in the EU internal electricity market, e.g., with respect to bidding formats and market clearing. Lastly, it discusses different integration scenarios, in which individual countries experiment with nodal pricing in the (coupled) EU internal electricity market.

6.2 Nodal vs. zonal pricing

6.2.1 Overview and development of nodal and zonal pricing

Historically, electricity markets have been operated by vertically integrated monopolists, often operating generation, transmission, and distribution of electricity [101]. During liberalization of electricity markets, i.e., allowing for competition where economically possible and applying regulation elsewhere, different market designs have emerged in the US and the EU [33]. Electricity markets inhibit a set of peculiarities demanding carefully designed markets to meet the physical and economic characteristics of the good (i.e. electricity). In the EU, zonal markets have emerged, where market prices are determined per bidding zone, mostly corresponding to a country. In contrast, liberalized markets in the US are operated as nodal pricing systems (often also referred to as LMP systems), in which electricity prices are determined at each network node. The two systems will be briefly introduced in the following, where their main differences will be examined.

In a zonal market, generators and consumers of electricity typically bid and offer electricity in multiple sequential auctions and exchanges. All bids and offers within one zone are collected regardless of the market participants' location [23]. The intersection of zonal electricity demand and supply yields the zonal market-clearing price, which is the same for all market participants in the entire zone. The day-ahead market results usually constitute the central reference point, and short-term deviations are settled in subsequent intraday markets. The day-ahead market-clearing result might lead to a physically infeasible dispatch, for example due to the disregard of thermal limits of transmission lines[2]. In that situation, the dispatch

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[2]The day-ahead market-clearing result might lead to a physically infeasible dispatch due to the disregard of the physical constraints of the transmission grid [or physical limits on power flows through the transmission lines] caused by, for example, the thermal limits of transmission lines.

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is adjusted by so-called redispatch, which ensures that physical constraints are not violated [83]. Grid operation is typically separated from the market operation, as market operation is carried out by Nominated Electricity Market Operators (NEMO) while grid operation is performed by regulated transmission system operators (TSOs) [82]. There can be more than one NEMO operating zonal markets in the EU. However, order books of all NEMOs for a zonal market will be merged.

In a US nodal market, market operation and grid operation are carried out by the same entity, the Independent System Operator (ISO), or equivalently the Regional Transmission Organization (RTO) [82].[3] Market participants' bids and offers are collected by the ISO/RTO for each node, and prices are determined by matching supply and demand on the nodal level. Transmission capacities are incorporated when calculating market results by considering the thermal capacities of respective lines.[4] If sufficient transmission capacities are available, excess demand can be supplied by possibly lower-cost generation from neighboring nodes. If transmission capacities between two nodes are exhausted, different generators might supply the price-setting quantity of electricity in the two neighbouring nodes respectively, leading to diverging prices between the two nodes. In theory, nodal pricing leads to the welfare-maximizing solution, and the dispatch in nodal pricing systems does not require subsequent redispatch, as physical constraints are directly included. Further, locally diverging prices serve as long-term locational price signals for lacking power generation or excess power supply. If the price signals are robust and stable, such that corresponding capital allocation is induced by the prices (i.e., power generation capacities and industrial demand), the need for grid expansion can be reduced.

Numerical simulations of energy markets have been widely used to compare market results of nodal pricing and zonal pricing scenarios (e.g., [72]; [142]). These studies indicate welfare gains due to efficient electricity dispatch and long-term investment signals for transmission lines and generation capacities (for example summarized in [15]). In addition to simulation studies, shadow solvers may be implemented that run in parallel to current zonal markets and help assessing the impact of nodal pricing already before the market design transition. In that regard, possible price differences between nodes can be anticipated and analyzed in more detail early on.

6.2.2 Market coupling of zonal markets vs. coupling of nodal markets

Whenever there exist available cross-zonal capacities, seams issues between these markets emerge. Seams issues can occur, for example, due to different regulatory requirements, market design differences, or technical differences between markets, hindering the efficient usage of transmission capacities between markets [100]. For example, without market coupling of any form, traders who aim at purchasing energy from a neighboring market must purchase both the transmission capacity and the energy separately. Coupling markets can significantly increase welfare on both sides of coupled markets by reducing transaction costs, increasing liquidity on both sides, and enabling feasible trades [119]. Furthermore, with no measures and rules for market coupling in place, electricity flows can differ highly from scheduled flows, leading to loop flows. Again, the historical development of market designs in Europe and the US has led to different measures dealing with seams issues.

In the US, the most significant and most effective measures to solve seams issues have been to merge previously separated markets. This effectively removes technical, economic, and legal seams by running the whole market under the same set of rules, including real-time pricing rules. For example, before merging separated markets into the PJM Interconnection, market coupling between the involved markets had to be organized by each party involved. This includes the cost allocation of transmission capacities, real-time pricing of energy, and interaction of different congestion management methodologies [119]. Currently, the PJM Interconnection includes 13 states and one district, and additional transmission systems are being integrated [115]. Similarly to the PJM Interconnection, the Midcontinent Independent System Operator (MISO) has gradually grown over time. The growing geographical span of these RTOs effectively deals

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[3]In the case of a grid operator that operates across state lines, the operator is referred to as a Regional Transmission Organization (RTO), such as Pennsylvania-New Jersey-Maryland (PJM) Interconnection, which operates in several states in the eastern United States.

[4]See subsubsection 6.4.5 for a discussion of different market organization forms.

with seams between formerly separated systems. Nevertheless, still, many seams exist between RTOs, ISOs, and non-liberalized electricity systems. The Federal Energy Regulatory Commission (FERC) has specified a set of broad regulatory rules for ISOs/RTOs to facilitate market coupling and reduce transaction costs [69]. However, the specific measures put into place to deal with seams issues differ from border to border. For example, PJM and MISO have signed the Joint Operating Agreement (JOA), active since 2004. JOA regulates the calculation of market flows to resolve issues evolving due to different congestion management methodologies in detail [114]. Further, [158] discuss existing algorithms coupling electricity markets in the US and propose a new decomposition algorithm. In a broad sense, with the proposed algorithm, TSOs/RTOs solve the dispatch within their own area, while taking into account the marginal units and binding constraints of neighbouring TSOs/RTOs. Every party involved does this repeatedly until convergence is reached. This in principle leads to an optimal coupling solution, while having institutional separately responsible ISOs.

Coupling zonal markets requires a fundamentally different approach compared to coupling nodal markets. As observed in the US, nodal markets historically have mainly been coupled by fully integrating a system into one RTO. However, in zonal markets, this approach would enlarge bidding zones, as prices are determined for the whole zone. Therefore, fully integrating markets would constitute an enlargement of bidding zones (see [61] for a discussion of bidding zone configurations). This, in turn, may increase the need for redispatch measures as the probability of physically infeasible market outcomes increases. In fact, the amount of redispatch measures at the national border increased when a unified German-Austrian bidding zone was formed, and hence the unified zone was split up into two [20].

There are numerous zonal market borders within the internal European electricity markets, and many market coupling mechanisms are in place. Since the day-ahead market serves as the primary reference point in most zonal markets, the most significant effort for coupling zonal markets is put towards day-ahead coupling through Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA). EUPHEMIA couples zonal markets by a flow-based model, available transfer capacities, or a hybrid system of both (see the following subsections for a discussion). By EUPHEMIA, available transmission capacities, available for cross-zonal trading of electricity are being determined. Moreover, further specific measures are already in place or are under development to couple zonal markets also at the intraday timeframe and to couple balancing systems. In the following sections, concrete European market coupling measures will be discussed.

6.3 State of practice and current development of the Internal Electricity Market

6.3.1 Day-ahead markets

As discussed above, day-ahead markets constitute the main reference point for zonal European markets. A preliminary dispatch and corresponding prices are determined, while any short-term deviations are corrected in subsequent intraday markets. Day-ahead markets are organised as centralized auctions, where participants express their economic value for the amount of electricity they may supply or consume at each hour of the following day. For example, generators may express the possible amounts and the associated costs of power generation and consumers may submit bids expressing how they would adjust their consumption given the prices they face. Supply and demand are then matched according to the submitted bids, in a manner that maximizes welfare, respects constraints on dispatch and/or prices, and accounts for some representation of physical transmission constraints.

In Europe, the interconnected national wholesale electricity markets are integrated via the *Single Day-Ahead Coupling (SDAC)*, aiming to allocate the cross-border capacity in a welfare-maximizing fashion. More specifically, each generator and consumer submits bids according to certain bid formats to the NEMO serving the bidding zone they are associated with. At the same time, TSOs determine relevant transmission grid constraints for cross-border interconnector flows according to different methodologies. Notably, transmission constraints within a zone are largely ignored. The bids of the market participants along with transmission constraints then serve as input to the above mentioned EUPHEMIA algorithm. The algorithm determines market clearing and hourly zonal electricity prices. Since supply and demand may also be matched between bidding zones as long as the resulting flows respect the transmission constraints, the

joint clearing of coupled European markets allows to realize significant welfare gains, as discussed in Section 6.2.2. The following sections discuss available bid formats, representations of grid constraints, and the functioning of the EUPHEMIA algorithm in greater detail.

Bidding Language and Pricing

Broadly speaking, EUPHEMIA allows the submission of three different classes of bids [124]. Hourly bids stipulate the sale or purchase of electricity at a given price and a given hour. A block bid, in turn, is a set of hourly bids whose acceptance depends on the satisfaction of certain conditions, depending on the type of block bid. Finally, complex orders allow expressing more nuanced cost structures or technical restrictions. It is important to note that not all NEMOs provide the entire set of bid formats [146]. For instance, while most NEMOs provide hourly and block orders, complex orders are available instead of block orders in Spain and Portugal.

In the European day-ahead market, each bid is cleared at the zonal price, with no side payments. Thus, European pricing requires that *Paradoxically Accepted Bids (PABs)* must not exist. PABs constitute bids which are accepted despite being *out-of-the-money*. However, this necessitates the existence of *Paradoxically Rejected Bids (PRBs)* instead – bids which are rejected despite being *in-the-money*. European market clearing also imposes the condition that hourly bids are never paradoxically rejected, which means PRBs consist of block orders and complex orders only.

Hourly orders constitute a set of price-quantity pairs that express the willingness to buy / sell certain amounts of electricity at different prices. Hourly orders are generally available at all European NEMOs. The pairs of prices and volumes are translated into demand / supply curves using either stepwise or linear interpolation. EUPHEMIA also takes into account an idiosyncrasy of the Italian market. Italy is divided into four bidding zones, yet hourly demand bids are cleared at a single national price, the so-called Prezzo Unico Nazionale (PUN). As discussed below, the requirement to avoid paradoxically accepted PUN orders implies a significant complexity for the EUPHEMIA algorithm.

A block order is a supply or demand order which contains a set of hourly periods, an average price limit over the set of periods, and a volume demanded for each period. If a block order is accepted, the volumes at each hour will be accepted. Block orders are available in all but a few NEMOs (e.g., OMIE in Spain and Portugal).

Several variants of block orders exist, although not all of them are available in each NEMO. For example, aside from the standard regular block order described above, block orders can be submitted as *curtailable orders* with a minimum acceptance ratio. If the block order is accepted at a given ratio, volumes at each hour will be accepted at that ratio. Moreover, block orders of a market participant may be *linked* in families such that a child block order is accepted only if its parent is accepted, and income from a child order can allow for the acceptance of a parent order whose Minimum Income Condition (MIC) (see below) is violated. Block orders can also be placed in *exclusive* groups, amongst which at most one can be accepted.

Besides not being available in each NEMO, not all types of block orders are available in each NEMO, and not all types of block orders are identical in their implementation. For instance, for the Nordic region, Nordpool offers a specific bundle of block bids in an exclusive group under the name *flexi order*. A flexi order consists of a block of at most 23 consecutive hours and a flexible time interval for acceptance. The algorithm then optimally schedules the blocks to maximize welfare. In contrast, the European Power Exchange (EPEX) Spot offers *loop orders*, which are two block orders that must be accepted or rejected together. Both NEMOs allow for regular, curtailable, linked, and exclusive blocks as well as combinations thereof. For Nordpool, however, an exclusive group has to maintain a minimum acceptance ratio of at least 50 %.

Complex orders are sets of hourly bids, which can be subject to a Minimum Income Condition (MIC), a load gradient constraint, and/or a scheduled stop. A MIC stipulates that the value of an accepted subset of hourly orders must equal the submitted cost of production, represented by fixed startup cost and a constant marginal cost of electricity (in €/MWh). A scheduled stop allows a generator to gradually wind down production in case their order is rejected due to the violation of the MIC. A load gradient limits the variation on power generation between each hour. Complex orders are available in the Iberian market and

Ireland.

A Scalable Complex Order (SCO) is a modification of a complex order and is currently under development with a go-live planned for 2022 [145]. For the minimum income condition, the constant marginal cost of electric power is replaced by the cost inferred from the hourly bids contained within the SCO. Moreover, the fixed term is incorporated explicitly in the welfare objective. SCOs also allow for a minimum acceptance volume per hour condition, specifying a minimum generator load at each hour. Scheduled stop and load gradient conditions can also be specified, and a demand-side version is available where the minimum income condition is replaced by a maximum price condition.

Zonal Models of the Transmission Grid

The objective of SDAC is to facilitate the trade of electric power across the price-coupling region. Current flows on the transmission grid obey certain physical laws, which put constraints on how interconnected markets can exchange electricity. EUPHEMIA models such constraints on the power flow on intercon-nectors either by *Available Transfer Capacities (ATC)*, by a *Flow-Based (FB) model*, or by a hybrid model incorporating both [124].

In the ATC model, each interconnector is modelled as a line on which electric power may be sent in each direction, up to the limit enforced by transfer capacities set by the respective TSOs. Lines can suffer from losses – meaning that energy sent from one end need not equal energy received on the other. Each line may also be operated by an independent entity, which may charge tariffs on the power flow. Finally, additional ramping constraints may be enforced on the power flow on lines, limiting the hourly variance of flow. Given such constraints, the available transfer capacities are available for cross-border trading between zones. Most of the European grid is modelled by ATC constraints. However, it should be noted that trades between two bidding zones do not necessarily reflect all flows on the respective interconnectors. For instance, an intra-zonal trade within a single zone might also imply power flows through interconnectors and neighboring zones, before circling back to the original zone. Similarly, a trade between two zones might also involve flows through other bidding zones. This is what is referred to as a *loop flow*, and the simple ATC model fails to anticipate them.

To rectify the issue of unaccounted loop flows in the ATC model, *Flow-Based Market Coupling (FBMC)* was introduced within Central Western Europe to model the flows between Austria, Belgium, France, Germany, Luxembourg, and the Netherlands. The FB model provides a better approximation of physical flows by also modelling the loop flows that occur as a result of cross-border trades. Each flow-based constraint provides a linear model of the directional flow on a branch via a so-called Power Transfer Distribution Factor (PTDF) matrix, which specifies how the net position of a bidding zone affects the flow on a branch. The flow on a branch is thus a weighted sum of net exports of bidding zones, which must not exceed the *Remaining Available Margin (RAM)* – the capacity on the branch reserved to accommodate loop flows. Both the PTDF matrix and the RAMs are provided by TSOs. While as of date the FB model is employed only within Central Western Europe, in 2022 the introduction of FBMC is foreseen in the Core region in Continental Europe.

It should be noted that FBMC does not entirely resolve the issue of loop flows. In particular, while FBMC accounts for the effect of cross-border trades on the flows through other interconnectors, it cannot include loop flows that are caused by purely intra-zonal trades. Moreover, FBMC (as well as ATC) is based on estimations, e.g., referring to PTDFs and RAMs. A comprehensive representation of grid constraints and all loop flows would be provided by a nodal pricing system.

Under the current framework, EUPHEMIA determines hourly zonal prices. As prices can thus differ at both ends of an interconnector, TSOs can collect congestion rents between zones. These rents are used to cover financial obligations arising from Long-Term Allocations (LTAs), i.e., previously allocated cross-zonal capacity [124]. The most recent EUPHEMIA version directly includes the LTA domain as part of the algorithm to avoid insufficient congestion rents to cover LTA obligations [117]. In particular, when a congestion rent shortfall may occur, EUPHEMIA adds virtual transmission lines over which trades may be executed to ensure coverage of LTA obligations.

Finally, EUPHEMIA can impose external constraints on the net positions of each bidding zone. These can

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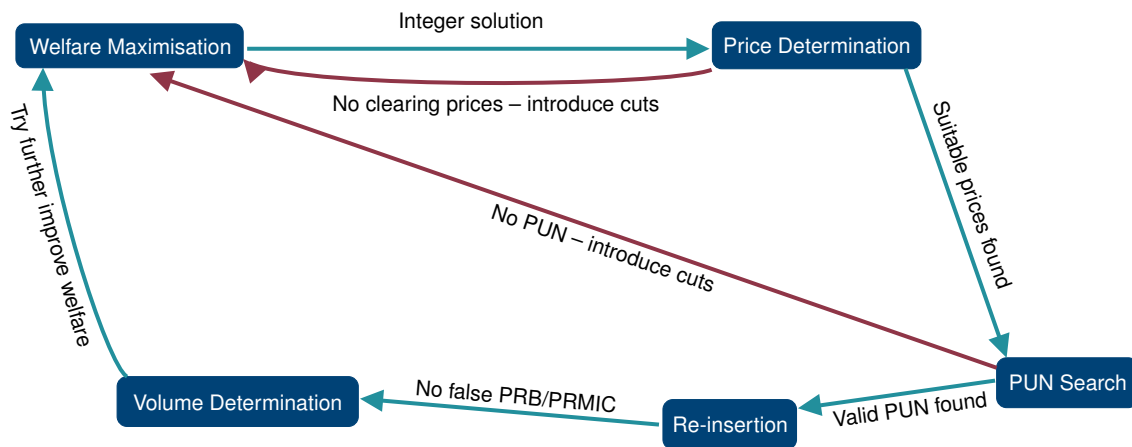
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Figure 9: A diagram depicting the multiple stages of EUPHEMIA's optimization procedure as it attempts to find a welfare maximizing dispatch and suitable prices.

take the form of import-export constraints, which explicitly limit the net position of a bidding zone, or ramping constraints, which limit its hourly variation. A "zero-hour" net position is also factored in to limit the variation in net position from the previous day. Ramping constraints may be violated, but only at an amount limited by the daily reserve capacity.

Algorithm

Given the bids, the transmission constraints, and the import/export limitations between bidding zones, EUPHEMIA solves a multistage optimisation problem to compute the preliminary dispatch – iteratively maximizing welfare, determining zonal prices and accepted PUN orders, and determining flows as shown in Figure 9 [124]. In the welfare maximization stage, EUPHEMIA computes a dispatch which maximizes social welfare, subject to constraints related to the acceptance of most bid types, constraints arising from the model of the transmission grid, and the external constraints on the net position of bidding zones. Social welfare is simply the value of accepted demand bids minus the value of accepted generator bids, which respectively correspond to the value of electricity consumption and the cost of generation. A penalty term is also added to the objective, which serves to equalize *curtailment* of supply or demand amongst bidding zones when local supply and demand are not equal and one must be partially met.

Once a welfare-maximizing solution has been found, EUPHEMIA proceeds to price determination, checking if there exists a set of zonal prices coherent with the set of accepted bids. Such prices must ensure that no block bid is paradoxically accepted, while making sure that any in-the-money hourly bid is accepted. Furthermore, an intuitive economic condition that trades should respect is that a bidding zone with a low price exports to a bidding zone with a high price, and not vice versa. However in FBMC, coefficients in a PTDF matrix can be negative, signifying when grid congestion can be relieved by having a bidding zone export more power. This can cause situations where a low price zone exports electricity to a higher price zone, allowing increased welfare from congestion relief. EUPHEMIA supports a bilateral intuitiveness mode which allows for the suppression of such *adverse flows*, though not taking advantage of the congestion relieving effects of such flows comes at a welfare loss. Finally, when there are two bidding zones with negative prices, it should not be the case that they both deliver power to each other to benefit from losses on the transmission line. A solution may contain such a flow when electricity prices are negative and welfare is improved by trading electricity back-and-forth on a line, destroying electric power. However, such a flow is not physically sensible, and thus needs to be eliminated from the final allocation. If any of these conditions are violated, EUPHEMIA produces a constraint to be added to the welfare maximization problem and starts over.

If the price determination is successful, EUPHEMIA proceeds to the PUN search problem, i.e., the problem

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of determining which PUN orders can be cleared. If no solution is found that does not introduce para-doxically accepted block bids or violates other constraints, EUPHEMIA again tracks back to the welfare maximization problem, adding a constraint which eliminates the current candidate solution from consideration.

Once all prices are set, EUPHEMIA attempts a re-insertion of *false* Paradoxically Rejected Minimum Income Condition (PRMIC) orders and Paradoxically Rejected Bids (PRBs), checking if they can be accepted in a feasible solution where market clearing prices exist for each bidding zone and the social welfare has not degraded. This is accomplished through an iterative procedure. EUPHEMIA forms a list of potential false PRMIC orders. For each order in the list, EUPHEMIA tries accepting the bid and goes back to price determination. If price determination is successful, a new list is generated – else the bid is determined to be a true PRMIC. Next, EUPHEMIA attempts re-insertion of PRBs in a similar fashion. This re-insertion step continues until either no paradoxically rejected bids remain, or until the time limit is reached – as of date EUPHEMIA is required to provide a solution in 12 minutes (to be extended to 17 minutes by 08/07/2021) and the volume indeterminancy subproblem is estimated to require 3 minutes. Having determined accepted bids and prices, EUPHEMIA finally conducts a so-called volume determination and resolves indeterminacies in case multiple solutions remain, minimizing curtailment, maximizing accepted volumes, and producing a final set of flows between bidding zones.

Discussion

EUPHEMIA has helped couple almost the entirety of the European Economic Area (EEA) electricity markets, handling a trading volume of 1.530 TWh and providing an average of 8.9B€ of gains in trade per day in 2020[123]. Moreover, the algorithm accomplishes this with good performance, providing a first solution in an average time of 3.2 minutes and a maximum of 7 minutes, well below the 17 minutes of delivery time required from it. Still, there are issues pertaining to efficiency – both economic and specifically relating to its welfare maximization, the scalability of its performance as it faces increases in both the number of bids and market time units, and its transparency.

In fact, the most prominent criticism of SDAC appears to be the lack of transparency. In 2015, in their response to the EC's Consultation on a New Energy Market Design, ACER and Council of European Energy Regulators (CEER) had noted *"We would particularly like to see clearer rules and greater transparency around the market coupling algorithm (EUPHEMIA)."*[11]. Whereas several measures have been taken to ensure transparency, such as the publishing of the EUPHEMIA Public Description as well as annual reports, complaints about the (in)transparency of the process persist. In 2020, a report of the Austrian Energy Agency notes *"It is therefore an urgent necessity to remove existing barriers that continue to restrict market transparency to this day. For the most part, these barriers ... are a consequence of a lack of usability leading in turn to disproportionately high search and transaction costs."*[17].

Research and development on the performance of the algorithm so far have been successful, with the Time To First Solution (TTFS) of the algorithm declining by 6 % in 2020 compared to the previous year. Furthermore, several scalability issues have been overcome by innovations such as extended LTA inclusions, processing of complex order heuristics earlier, and the introduction of scalable complex orders. However, these innovations are currently insufficient for the implementation of a 15 minute market time unit, with projections that the algorithm may vastly exceed the 17 minute time limit by 2024 (with an average TTFS of 2 hours)[123].

Another issue is the existence of PRBs in EUPHEMIA's solution. The utility loss from PRBs remains low [123], with an average of 24k€ per day and a daily maximum of 321k€. As the average daily surplus is 8.9B€, this suggests that the welfare loss from PRBs is not high. The existence of PRBs is nevertheless problematic, as it may provide incentives to misrepresent valuations. Different order types may be para-doxically rejected at different rates [111], providing wrong long-term incentives and reducing trust in market participants in fairness of outcomes [81]. That being said, elimination of both paradoxical acceptance *or* rejection of bids is impossible in the setting of electricity markets. In particular, when relying on uniform-prices, losses or opportunity costs cannot be avoided and uniform-price market equilibria need not exist. Thus, the elimination of PRBs would instead require *uplift payments* – compensations for paradoxically

accepted bids. Such a payment rule is a form of non-uniform pricing. The implementation of non-uniform prices is in fact currently investigated as a potential remedy to EUPHEMIA's scalability [123].

A final point is the possible non-optimality of EUPHEMIA's outcome. Such a question arises naturally as the existence of PRMIC/PRB re-insertion step suggests that an optimal solution is not reached as a result of the algorithm's branch-and-cut process. There is in fact evidence that EUPHEMIA's solution is near-optimal – the welfare difference between the first solution and the final solution has averaged $\sim$ .0002 % from 2017 to 2020, with a maximum welfare increment of 500k€ compared to the daily average welfare of 8.9B€. Improvements remain on the same order also if the algorithm is allowed to run for 10 more minutes. Furthermore, as previously remarked, the value of PRBs remain low. Nevertheless, the time limit given by the SDAC design can lead to inefficiencies, which may become a significant concern once 15-minute time intervals are considered or new bid formats are introduced.

However, that EUPHEMIA produces near-optimal solutions given its model does not imply full economic efficiency – that is, economic efficiency on a scale beyond that of the day-ahead auction. This is the case as, while the market clearing of EUPHEMIA may be near-optimal for the auction model it employs, day-ahead markets are only one part of a larger sequence of auctions that form the European electricity market and the auction model does not necessarily capture the entire *social cost* of a dispatch. In particular, as zonal computations *ignore the majority of the transmission constraints of the grid*, unaccounted-for grid congestion defers costs to redispatch and balancing & reserve markets, causing an overall loss. Research suggests that the cost of such a deferral may be significant enough to offset possibly lower prices from zonal pricing [86].

6.3.2 Intraday markets

Intraday markets follow after the day-ahead markets and allow market participants to adjust their production and consumption schedules close up to delivery,[5] as they receive new information. This especially allows market parties to incorporate the resolving uncertainties regarding renewable production, demand projections, and power plant failures.
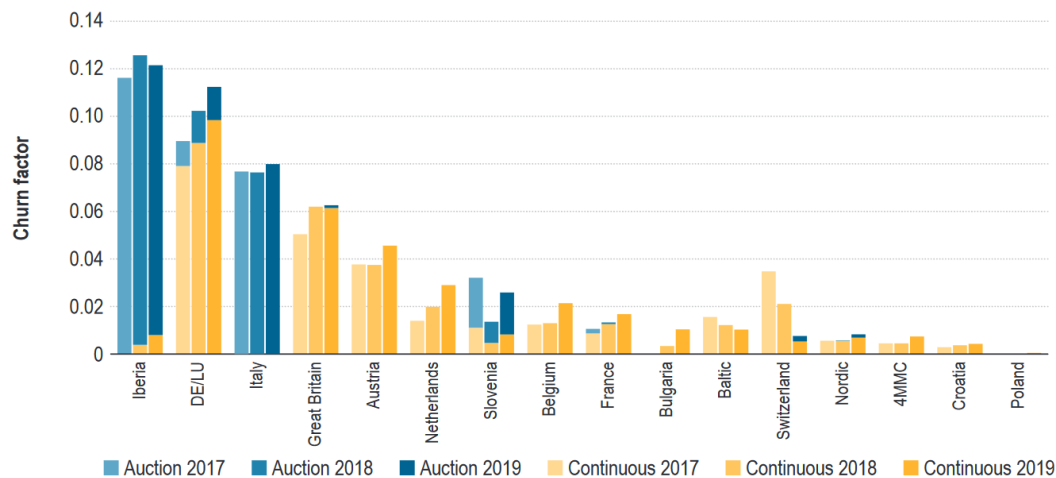
European market integration is done under a *Single Intraday Coupling (SIDC) (formerly known as Cross-Border Intraday Market (XBID))*, which employs a continuous trading mechanism to allow trading across zones, if transmission capacity is available, and within zones when transmission constraints are binding. In addition, several zones currently employ intraday auctions, either preceding the continuous trading or co-existing with it. The SIDC is scheduled to introduce three implicit cross-border coupled auctions (15:00 the day before, 22:00 the day before and 10:00, the day of delivery, cf. [147]) until the 1st of January 2023 [148], replacing existing solutions and building on the infrastructure of the (SDAC). In the following, the continuous SIDC design will be discussed, followed by a comparative discussion of Intraday Continuous (IDC) and Intraday Auction (IDA) trading.

Continuous intraday trading under the SIDC

Continuous trading allows market participants to enter offers (or bids) into an order book at any time, and as soon as a sell order has a lower price than a buy order, a transaction is performed, affecting only the two bilateral market parties.

In the SIDC, this general concept, known, e.g., from stock trading, is extended to incorporate restrictions for cross-border trade of electricity. It is based on a Shared Order Book (SOB), a Capacity Management Module (CMM), and a Shipping Module (SM) [148]. Orders are matched internationally only if transmission capacity is available. Transmission capacity is allocated on a first-come-first-serve basis, and the CMM is updated after each trade. Currently capacity restrictions are implemented in the ATC model (cf. 6.3.1), but this is scheduled to be extended to a FBMC (cf. 6.3.1), albeit with restrictions as will be detailed in the discussion. The shipping module provides information on concluded trades to all relevant stakeholders.

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[5]With cross-border gate closure times usually 30 to 60 minutes before real-time, with the exception of the Netherlands and Belgium, which allow trading up to 5 minutes before real-time [148].

Source: Volumes from nominated electricity market operators (NEMOs) and demand from ENTSO-E Transparency Platform.

Note: Croatia only started its ID market in April 2017, Bulgaria in July 2018, and Poland when it joined SIDC in the second wave in November 2019.

Figure 10: Yearly intraday churn factors in major European markets, from the ACER/CEER Market Monitoring Report - Volume 1, 2020 Electricity Wholesale Market Volume [10]

The SIDC is now, with the 3rd wave of extensions, covering interconnections to and from Italy. Overall, a large majority of all EU member states is part of the SIDC (with the exception of Greece and Slovakia) [147].

The traded products include 15-minute, 30-minute, and hourly trading, as well as blocks covering several hours. Only hourly products are currently traded in all SIDC countries [148], with Germany, Austria, the Netherlands, Belgium, Hungary, Romania, and Slovenia also trading 15-minute products (even less countries trade 30-minute products) [148].

Discussion of the merits of continuous and auction-based trading

As described previously, intraday markets are currently predominantly implemented as a continuous market. However, some member states have intraday opening auctions (e.g., Germany), or regular intraday auctions (e.g., the Iberian peninsula and Italy), and the SIDC is scheduled to include three intraday auctions as stipulated by the European Capacity Allocation and Congestion Management (CACM) regulation [148]. This section will discuss these two different market designs across several criteria (extending the discussion by [125]).

Liquidity and market depth: Auctions "collect" liquidity over time, and thus make the market more attractive to market participants. The introduction of the opening intraday auction in Germany in 2015 doubled liquidity in the least frequently traded periods, and still increased market volumes by 20-30 % in the most traded periods [99]. This is also reflected in the liquidity of intraday trading between European member states. As can be seen in Figure 10 fewer member states use auctions, but two of the three regions with the highest liquidity have auctions as the dominant trading paradigm (notably the Iberian peninsula as the most liquid intraday market, measured by churn rates, i.e. the traded volumes divided by the actual electricity delivered) [12]. Similarly, market depth (i.e., the total volume that can be traded in a single transaction) is a magnitude higher in the German opening auction than in the following continuous trade [99].

Allocative efficiency: Due to the first-come-first-serve rule, continuous trading more easily results in welfare violations, as it is the sequence of trades, not the costs and demands that determine absolute welfare and its distribution [16]. Secondly, rents from transmission constraints are awarded on a first-come-first-serve basis, and not allocated to TSOs.

Suitability as a reference price: Continuous trading is inherently pay-as-bid (i.e., the bids directly determines the payments), whereas wholesale electricity markets are usually conducted as pay-as-cleared. This means that an actor holding a financial derivative defined on a continuous intraday-market reference price (which is inherently defined as average prices of individual transactions over a certain period) cannot be sure, to actually trade at that reference price. An evaluation of trading data in Germany from 2014 to 2015 [99][6] showed that cap-futures on an average reference price (i.e., futures that pay out when a certain reference price level is exceeded), had a basis risk exceeding 86 €/MWh in 5 % of all trades (i.e., a deviation of actual trades from the index). Auctions that are pay-as-cleared have no such basis risk.

Representation of network constraints: Electricity flows are governed by physical laws of networks. In such networks, any trade will not only affect the flows in the shortest pathway between two trading partners, but (to a degree) also many other lines. As a result, bilateral trades only involving two trading partners can only partly utilise a constrained network [16], as often trades involving three or more trading partners are needed, and a splitting up in sequential bilateral trades would not be welfare enhancing in all individual trades.

Depiction of unit constraints: Currently only simple bids are traded with high liquidity in the SIDC, with no cross-product matching (i.e. 15 minute, with 30 minute products or blocks) occurring. While this is scheduled to be implemented [147], due to the first-come-first-serve trading such cross-product matching is not likely to occur very often. Simple bids do not allow market participants to explicitly express inter-temporal constraints (e.g. a battery that can only discharge a certain amount of energy of a certain cumulative period, or a power plant having start-up costs), and thus result in inefficiencies under uncertainty [137] and non-convexities. Multi-part bids can represent such constraints, but are inherently unsuitable for continuous trading.

Information efficiency: In principle, each time the (expected) scarcity situation changes, a trade should be conducted [125].[7] Secondly, due to transaction costs and typical intervals of information arrival (e.g., market participants receiving renewable production forecasts), market participants have the interest to trade at certain times, and not others [79]. Continuous trading in principle allows market participants to trade at any time (while changing liquidity over time may make certain periods more attractive than others, independent of individual's preferences), which is highly beneficial from an information efficiency perspective. One reason for efficiency gains is that the merit-order gets steeper over time, since fewer flexibility options are available close to real-time. The earlier the information is incorporated, the more sufficiently flexible generators are left in the market. The incorporation of new information by auctions, on the other hand, crucially depends on the frequency of auctions, and should approach continuous trading for very frequent auctions (which may be limited by computational constraints, for example).

6.3.3 Balancing markets and imbalance pricing

Balancing reserves are used for load-frequency control to restore the set-point frequency, which is 50 Hz in Europe, if feed-in deviates from consumption of energy. Such deviations can occur, e.g., due to power outages or unexpected fluctuations in consumption. In case of a deviation, Frequency Control Reserves (FCR), also called primary reserves, are activated within seconds to limit the deviation. Within minutes, FCR are replaced by automatic Frequency Restoration Reserves (aFRR) (secondary reserves) and later on – if necessary – by manual Frequency Restoration Reserves (mFRR) (tertiary reserves) to restore the normal frequency. Some countries use a Replacement Reserves (RR) product in addition. The reserves (capacity and energy) are procured by the TSOs [153].

This section focuses on the European balancing energy markets for aFRR and mFRR, which are scheduled to start mid-2022 and will replace the national markets of the participating nations. European platforms that are already in operation are those for RR and Imbalance Netting (IN). The TSOs' implementation projects to establish the European platforms for aFRR, mFRR, RR, and IN are called Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO), Manually Activated Reserves Initiative (MARI), Trans-European Replacement Reserves Exchange (TERRE), and

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[6]The reasoning of this paragraph is based on idem.
[7]There is also an efficiency limit to speedy trading, as [25] show for stock markets.

International Grid Control Cooperation (IGCC), respectively [42]. An integrated European procurement of balancing capacity is not yet planned, but guidelines for cross-border cooperation exist [Article 25 136, 4] and the Nordic TSOs will establish a regional aFRR balancing capacity market [42]. The EC's Electricity Balancing Regulation (EBR), also known as Electricity Balancing Guideline (EBGL) [136], provides the basic rules for the balancing energy markets' design, and multiple decisions by ACER provide further details [5, 6, 7]. These rules and decisions harmonize procurement of balancing energy in Europe and limit the options for national design specifics.

In the future European balancing energy markets, the TSOs collect energy bids in their regions (or bidding zones) and transfer them to the European platforms for aFRR and mFRR, where they are ordered by price to get the Common Merit Order List (CMOL). Both for aFRR and mFRR, there is a separate product for positive balancing energy, which is used to counter an energy shortage, and for negative balancing energy, which is used to counter an energy surplus.[8] Any bid has a validity period of 15 minutes. Each day is divided into 96 non-overlapping validity periods. The Gate Closure Time (GCT) is 25 minutes before the validity period begins, and TSOs must provide the bids until 10 minutes before GCT for aFRR and until 12.5 minutes before GCT for mFRR. This is the result of an effort to move the GCT as close as possible to real time. The maximum and minimum balancing energy prices and bids have been set to 99,999 €/MWh and $-99,999$ €/MWh, and the minimum bid volume is 1 MW [5].[9]

Besides the bids, the platforms also collect the available cross-border transmission capacities (i.e., the transmission grid constraints between bidding zones but not those within bidding zones) and the TSOs' demands for balancing energy. The activation optimization functions of the platforms then determine which bids are activated. Roughly speaking, the optimization aims at satisfying TSOs' demands by the lowest bids while respecting cross-border capacities. The optimization is done for every Market Time Unit (MTU). The length of an MTU for aFRR is equal to the length of an optimization cycle of the platform, which will be about four seconds, whereas the length of an MTU for mFRR with scheduled activation is 15 minutes.[10] The next step is the determination of prices, which are called Cross-Border Marginal Prices (CBMPs). This step uses so-called uncongested areas: The activated bids and the cross-border capacities either result in one uncongested area consisting of all bidding zones or in multiple uncongested areas that are uncongested within themselves but have binding cross-border capacity constraints between them.[11] For each uncongested area and each MTU, one CBMP is determined. The CBMP for positive balancing energy is equal to the highest activated bid in the uncongested area. For negative balancing energy, the CBMP is equal to the lowest activated bid in the uncongested area (due to the rule of sign applied to these bids, see Footnote 8).

The joint use of a CMOL instead of national merit order lists improves efficiency and on average increases competition. In addition, IN, that is, the avoidance of activating balancing energy in opposite directions in neighboring regions, reduces the demand for balancing energy and supports efficiency of the markets. The European platform for IN is already in use [8, 59]. As of June 2021, 20 TSOs performed IN via the platform [60].

As consumers of balancing energy, the balance responsible parties (BRPs) pay for balancing energy in case of imbalances. The EBR [136] sets the basic rules for the determination of the imbalance price, which has to be paid for imbalances in an Imbalance Settlement Period (ISP), and ACER [9] concretizes the rules.

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[8]Sign conventions on prices are such that a positive balancing energy price (> 0) for activated positive balancing energy is paid by the TSO to the supplier, whereas a positive balancing energy price (> 0) for activated negative balancing energy is paid by the supplier to the TSO. Thus, the CMOLs order bids for positive balancing energy in ascending order and bids for negative balancing energy in descending order. Typically, all bids for positive balancing energy are positive, and also the first bids in the merit order list for negative balancing energy are positive (as suppliers are willing to pay, e.g., because they reduce costs by reducing generation).

[9]ENTSO-E [58] has requested to reduce the absolute value of the maximum and minimum prices for balancing energy bids. Adjusting maximum and minimum prices can reduce inefficiency by incorporating the maximum willingness to pay of the demand side and by increasing allocative efficiency of activating balancing energy bids by reducing incentives to submit excessively high bids [39].

[10]Next to mFRR with scheduled activation there is also mFRR with direct activation. Direct activation of mFRR can occur at every point in time of a validity period and bids are then activated until the end of the next validity period.

[11]As with EUPHEMIA for the day-ahead market (see Subsection 6.3.1), only cross-border capacity constraints are taken into account by the platform, whereas transmission constraints within bidding zones are not known by the platform. Thus, within uncongested areas there are no binding cross-border transmission constraints but congestion within bidding zones is possible.

The balancing energy price is a main determinant of the imbalance price.[12] Each ISP corresponds to a validity period of 15 minutes. A BRP's imbalance in an ISP can be positive (energy surplus) or negative (energy shortage). ACER sets a single imbalance price for positive and negative imbalances as standard [9, Article 7]. The imbalance price in an ISP depends on the direction of the total system imbalance. The direction of the total system imbalance is negative if the total activated volume of positive balancing energy in the ISP is larger than that of negative balancing energy; it is positive if the reverse holds true. The basic imbalance price is determined by the CBMPs for positive (negative) activated balancing energy if the total system imbalance is negative (positive); it is either equal to the weighted average CBMP or the maximum (minimum) CBMP of the validity period that corresponds to the ISP. Next to choosing between these two methods for the determination of the basic imbalance price, the TSOs have some further flexibility for national adjustments of the final imbalance price. The basic imbalance price can be complemented by a scarcity component to increase prices in situations of scarcity, an incentivizing component to ensure sufficient incentives to avoid significant imbalances, and a component related to the financial neutrality of the TSO [9, Article 9]. Whether a BRP has to pay the imbalance price for its imbalance or receives a payment depends on the direction of the BRP's imbalance and on the sign of the imbalance price [136, Article 55]. Roughly, a BRP whose imbalance aggravates the system imbalance has to pay, and a BRP whose imbalance extenuates the system imbalance receives a payment.[13]

The European balancing market prices and the resulting imbalance prices are differentiated between uncongested areas. However, this locationally differentiated pricing is applied only on a high level, with bidding zones (TSO regions or nations) as pricing nodes, whereas prices within these bidding zones are always uniform. If European electricity wholesale markets used nodal pricing, a consistent design might require extending nodal pricing to balancing markets.

6.4 Integration scenarios

As discussed in Section 6.2.1, nodal pricing is one means to use transmission capacities more efficiently and to avoid costly redispatch. It can set the right locational incentives for sustainable technologies and flexible consumers, helping to achieve decarbonization and climate neutrality goals. Since a Pan-European move to nodal pricing requires significant regulatory and structural changes to electricity markets, it is more realistic that first individual zones or member states undertake such a transition. However, a coexistence of zonal and nodal pricing in Europe raises the question of how these market models can be integrated efficiently. In what follows, we discuss three broad options: sequential market clearing, hybrid market clearing, and full nodal market clearing across Europe.

6.4.1 Sequential market clearing

A sequential market clearing broadly refers to the option to compute the zonal and nodal market outcomes consecutively [138]. For example, in the day-ahead market, bids from the nodal level could first be submitted to the EUPHEMIA algorithm to determine a zonal market clearing as well as the zones' net positions and flows on interconnectors and critical network elements, as it is done today. Subsequently, in a second step, the nodal prices are computed for individual larger price zones, subject to satisfying the pre-determined net positions and power flows. Thereby, the nodal market clearing replaces the accepted bids by EUPHEMIA, while respecting the supra-regional restrictions imposed by the market coupling. This approach differs from current redispatch procedures as the market outcome provides a physically feasible solution as well as locational price signals for the nodal market.

In a similar fashion, this option can be implemented for IDAs and for the balancing time frame if this is feasible with respect to the tight time limits. In these cases, nodal market clearing would follow (potentially coupled) IDA or the clearing of European balancing platforms, respectively. IDC trading is more challenging

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[12]The EBR [136, Article 55] sets minimum levels for the imbalance price that depend on the balancing energy price, and ACER [9, Article 9] concretizes the ways in which the imbalance price can be calculated from the balancing energy prices.

[13]Concretely: In case of a BRP's positive imbalance and a positive imbalance price, the BRP receives a payment from the TSO (the imbalance price for each MWh of the BRP's imbalance); in case of a BRP's positive imbalance and a negative imbalance price, the BRP makes the payment to the TSO; in case of a BRP's negative imbalance, these two payment directions are reversed.

to align with the sequential clearing approach (a pre-screening of bids would be an alternative option, but would still introduce trading delays [138]). One possibility would be to clear the market in discrete time intervals (e.g., in the context of frequent IDAs) instead of continuous trading, as has recently been suggested for other reasons as well (see Section 6.3.2).

An advantage of sequential market clearing is that it requires comparatively little adjustments to current regulations and zonal market clearing processes. The subsequent nodal market clearing(s) would constitute an amendment on a regional level (i.e., for the nodal market jurisdiction), respecting all constraints imposed by the Pan-European zonal market outcome. For instance, the *Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing*[14] (Electricity Balancing Guideline) already allows for sequential market clearing.

While the sequential market clearing is a potentially feasible way to implement nodal prices under the current *EU Target Model in electricity*, it also comes with certain limitations. The initial zonal market clearing adds restrictions (referring to net positions and interconnector flows) to the subsequent nodal market clearing. As a consequence, the sequential market clearing cannot be seen as a full implementation of nodal pricing, since the social welfare and the price signals are still affected by the simplified zonal market outcome. Thus, it will not provide the efficiency gains that one can expect with other options.

Moreover, since in all time frames market outcomes need to be computed within tight time limits, there is only a narrow time window to perform the nodal market clearing in succession to the zonal market clearing. If the nodal market clearing problem cannot be solved to optimality, there might only be little welfare gains or benefits from locational prices.

Finally, a misalignment of traded products (i.e., zonal vs. nodal prices) across consecutive trading periods (be it the consecutive clearing, or the following intraday trading) can lead to gaming opportunities such as the inc-dec game. In fact, inc-dec gaming to profit from price differences between non-aligned consecutive markets can already be observed today in the context of market-based redispatch [121, 140]. Inc-dec gaming may also lead to a loss of liquidity or insufficient participation in the zonal market clearing [138]: if zonal prices are expected to be low and nodal prices expected to be high, generators will selectively not bid in the zonal market (or at a higher price) to then profit from the higher nodal prices. Vice-versa, load would in the same situation prefer to trade on the zonal market, but not the nodal market. As a result, generation and demand drift apart. In case of sequential market clearing, one way to mitigate inc-dec gaming is by using the same bids for both the zonal and the nodal market clearing.

Lastly, it would be essential to ensure a consistent financial settlement across Europe. On the one hand, if the zonal market clearing would be financially binding also for the nodal market, participants in the nodal market would essentially be subject to a double financial clearing (zonal and nodal).[15] This could set wrong incentives or lead to a violation of individual rationality for some participants. On the other hand, if only the nodal market clearing should be financially binding for nodal markets, this would require changes to current CACM regulations, demanding zonal trading and settlement. Moreover, the cross-zonal settlement processes might no longer be consistent. For instance, as discussed in 6.3.1, TSOs collect congestion rents between zones to cover financial obligations arising from LTAs. A subsequent nodal price computation, however, would alter congestion rents and might, thus, affect the Pan-European financial settlement.

Following the Brexit, TSOs from the European Union and Great Britain are tasked to design a so-called Multi-Region Loose Volume Coupling (MRLVC) between the EU and the UK. A recent cost-benefit analysis [29] suggests a sequential approach, where SDAC and UK clearing processes follow after the MRLVC. The report discusses potential impacts on SDAC timings and processes as well as operational and governance challenges. Since some of these aspects could apply for a sequential zonal-nodal clearing, learnings and design choices from the ongoing MRLVC development could be leveraged.

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[14]Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing C/2017/7774

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6.4.2   Integrated / hybrid market clearing

A more efficient outcome, compared to a sequential market clearing, could be obtained by clearing the nodal and zonal parts of the system simultaneously in a coupled model.

It has been demonstrated by [41] that a hybrid system with simultaneous coupling does not fully utilize all the resources in the network, and that price signals in the nodal pricing areas might still deviate from the "true" nodal prices. However, compared to zonal pricing, hybrid pricing results in better price signals within the area applying nodal pricing, and the need for re-dispatching can be reduced. Hybrid pricing will also affect the allocation of congestion rent, since it allows more congestion rent to be collected by the TSO in the nodal part of the system.

Implementing a hybrid market clearing model raises questions about how the interface between the zonal and nodal markets is to be represented. Should individual lines across the interface be represented, or should the interface be represented in an aggregate manner, as in a zonal model?

Several options exist to couple zonal and nodal markets from an algorithmic stand-point. A fully integrated nodal algorithm could be implemented (either based on EUPHEMIA, or on existing nodal solvers), which represents countries that opt for zonal clearing only on a zonal basis (including the current representation of critical lines), while fully representing nodal markets. Another option would be the coupling of separate zonal and nodal clearing algorithms, as is done in the US to couple nodal with nodal market, drawing on research of decomposed optimisation problems (cf. Section 6.2.2).

6.4.3   Full nodal market clearing

A full Pan-European nodal market clearing could incorporate all transmission constraints directly and, therefore, no longer require current market coupling frameworks. Locational prices could be computed at any node in the network. Markets that opt for preserving zonal prices could settle loads at some aggregate price. For example, the California Independent System Operator (CAISO) distinguishes between participating and non-participating loads, where the former are settled at nodal prices and the latter at aggregate zonal prices [28].

Clearly, this approach maintains the upsides of a nodal pricing system. Power flows are feasible and no redispatch is required. Nodal price signals reflect local scarcities and provide incentives for long-term investments, e.g., in flexibility. Short- and long-term efficiency gains can be realized [14]. Intraday trading could be realized through auctions in discrete time intervals or through coordinated bilateral or multilateral trading with public information on the transmission network [157].

At the same time, the computational complexity and, thus, the practical viability of a Pan-European nodal market clearing problem across Europe needs to be investigated. The move to 15-minute market time units, as currently planned for day-ahead markets, already quadruples the size of the market clearing problem and leads to computational challenges [123]. It needs to be studied if the current paradigm of computing market clearing and prices in a single optimization problem can incorporate nodal prices and is tractable within the time limits required. Decoupling market clearing and price determination could bring computational benefits and might be an important prerequisite for nodal pricing. In fact, it is currently being investigated as non-uniform pricing [123]. In this case, while the problem of PRBs (as discussed above) would no longer occur, uplift payments to compensate paradoxically accepted bids would be necessary. A second (non-exclusive) option would be to couple several nodal optimisation algorithms, for example via decomposition techniques, as is often done in the US (cf. Section 6.2.2). This may result in performance improvements, as well as improved (institutional) robustness.

6.4.4   Pathways to an implementation of nodal pricing

While nodal prices could be introduced in one step all over Europe, another alternative would be a stepwise implementation, starting with sequential market clearing or hybrid market clearing in some price zones before introducing nodal pricing across Europe. If it is not possible to introduce nodal pricing at the same

time in all timeframes (day-ahead, intraday, balancing), regulators need to investigate ways to quantify and mitigate possible gaming opportunities.

Currently, there are already efforts to include some nodal pricing elements in the current zonal model in order to bring the market outcome closer to what is physically feasible. For example, there are proposals to place generation units located in strategic places in the grid (i.e., places with a significant impact on congestion levels) in so-called dispatch hubs [40, 62]. These dispatch hubs can be considered a separate zone within the larger surrounding zones. Since flows from and to the dispatch hubs are taken into account by the market clearing algorithms, dispatch hubs provide additional degrees of freedom to manage congestion and increase welfare [40]. However, dispatch hubs are cleared at a different price than the surrounding zone and, thus, broadly follow the idea of locational prices. While dispatch hubs can build on existing market clearing processes and algorithms, many open questions remain regarding an unambiguous definition of dispatch hubs, just compensation schemes for affected generation units, as well as hedging, market power, gaming, and so forth. Dispatch hubs seem useful to include locational elements in the very short term, yet implementing nodal prices according to the options discussed above seems to provide more merits in the long run.

In this regard, the integrated clearing and in particular the full nodal market clearing across Europe can lead to computational challenges for the centralized clearing algorithms. Thus, each implementation step needs to be preceded by extensive computational studies making sure that the efficient dispatch and prices can be computed in due time. Regulators might also want to get familiar with the variations in nodal prices one can expect and the performance of different implementations. Therefore, a shadow solver that clears the market and computes nodal prices in parallel to the current solution is advisable to study the nodal system before it is put in place. Such a solver would not alter the current market processes, but merely compute the (non-binding and non-realized) outcomes of alternative market clearings under the different integration options. This requires additional data about the location of bids and the network topology provided by the TSOs and support by the governing bodies. In contrast, existing studies on nodal pricing (see, e.g., [15] for an overview) are based on (more or less restrictive) assumptions and many simplifications.

6.4.5 Market organization

An important difference between electricity markets in the EU and ISO markets in the US concerns the overall market organization. In Europe, the day-ahead and intraday markets are separated. NEMOs create legally binding arrangements to buy or sell electricity at the market price. Then trades are financially cleared by a clearinghouse. All nominated trades from day-ahead and intraday markets eventually result in dispatch instructions by the TSOs. If deviations occur, balancing energy is activated and imbalances are settled. Traded volumes in day-ahead markets (EPEX Spot 2020: 504 TWh [66]) are higher than in intraday markets (EPEX Spot 2020: 111 TWh [66]), as intraday markets basically serve the purpose of correcting the day-ahead schedules. Overall, the day-ahead markets are the central reference point in Europe and they are run by NEMOs, while the actual dispatch is the responsibility of the BRPs and TSOs.

In the US, the ISO organizes the trading and determines the efficient dispatch. Current US ISO markets center around two markets: day-ahead markets and real-time markets. On day-ahead markets, ISOs perform an hourly unit commitment and an economic dispatch of resources. The day-ahead market is financially binding, meaning the entire economic dispatch will be financially settled at the day-ahead price. Theoretically, it can happen that a generator who was dispatched in the day-ahead market is not dispatched in the real-time market, which determines the physical dispatch. Then, conceptually, the generator sells at the day-ahead market but buys back that quantity at the real-time market. In this case, prices typically do not increase, so that the generator can buy back its day-ahead quantity at a lower real-time price and avoid losses. In practice, virtual bids typically leverage such effects and thus prevent such situations for physical assets. Overall, a so-called two-settlement system is used. This means that only the deviations of the real-time dispatch to the day-ahead dispatch are financially settled at the real-time price (and not the entire real-time dispatch is settled at the real-time price).

The move to a fully nodal market clearing does not necessarily imply changes in the governance and overall market organization, but it is one of the issues that deserve discussion in such a transition. Generally,

several options seem to be conceivable and, thus, one-sided discussions on the establishment of an "ISO" are not adequate. Independent of potential organizational changes that would come with a fully nodal market clearing, a move to nodal prices requires regulatory changes early on. For instance, regulation should enable unit-based balancing and financial balancing responsibility and permit effective hedging possibilities (i.e., under Markets in Financial Instruments Directive (MiFID) II). Such aspects are further discussed in [14] and [15].

6.4.6   Flexibility market initiatives

Under any market organization and integration scenario for co-existing market designs, an important aspect in the decarbonization scenario of the European markets is the provision and procurement of flexibility resources for the power systems management. As discussed in Section 4, the ability to adapt generation and demand levels according to intermittent energy sources and systems' status is key to the efficient operation of grids, while providing the right incentives to cleaner and decentralized resources [96]. Specially in the European electricity market, composed by zonal day-ahead and intra-day markets, which do not consider intra-zonal network constraints (see also Section 6.3), System Operators (SOs) can use flexibility resources to reliably operate their systems in a cost efficient way. As discussed in Section 6.2.1, if the market is nodal, its clearing accommodates network constraints and the solution is always physically feasible. However, in zonal markets, the networks inside a zone are modeled as a copper plate, and each operator of each zone has to procure resources closer to real time to balance its system, manage congestion, control voltage, among others. Here, flexibility provision from cleaner and even distributed resources is key to reduce SOs costs when operating the systems (e.g., resolving a network constraint using flexibility in a context where consumption and generation are less predictable may deliver better value to consumers than traditional investments to reinforce networks [73]), while giving the right incentives to decarbonized technologies.

The "Clean Energy for all Europeans" package [67] defines that creating market frameworks to correctly reward flexibility is an effective way to meet its renewable energy targets. Flexibility markets for trading and commoditisation of energy flexibility are, thus, one possibility to make flexibility resources available to SOs, while correctly rewarding providers. Those markets can be created for multiple purposes (e.g., congestion management of an specific TSO), can be local or central (e.g., account for the needs of one DSO, or include TSOs and DSOs of different market zones), can use different market mechanisms (e.g., pay-as-bid, uniform, or pay-as-cleared), can give different levels of access to flexibility (e.g., a TSO has access to Distributed Energy Resources (DERs)), can include resources prioritization (e.g., an specific buyer clears first), among others. Moreover, flexibility markets are promoted by the EC, as they can contribute to the climate-neutral goals because they "help energy networks to monitor energy flows and create market signals to motivate changes in energy supply and demand, integrating smart meters, smart appliances, RES, and energy efficient resources accordingly" [55].

Even though, TSOs are already accustomed to procure flexibility to meet their needs in the current European market landscapes [73], e.g., for system balancing as discussed in Section 6.3.3, a few challenges related to the use of DERs and to the use of flexibility for other system services need to be addressed. Among them, flexibility markets need to be designed to enable DER participation and the procurement of their flexibility by TSOs, while accounting for the impact on distribution systems. Also, market-based procurement processes of flexibility for other system services, as congestion management and voltage control, need to account for network constraints in the clearing process, which is not the current practice in Europe. Some flexibility market initiatives, notably the TSO-DSO coordination for the procurement of flexibility, are under analysis in Europe, both to increase the number of market participants and to give SOs access to flexibility from multiple systems to manage their needs (including balancing and congestion management). Examples of projects and platforms for the procurement of flexibility from resources connected to the different voltage levels to solve congestion, control voltage, and/or balance the systems are CoordiNet [18], OneNet [96], and GOPACS [38].

In CoordiNet, for example, some market models were proposed to enable SOs to procure flexibility from different voltage levels (both transmission and distribution systems) in order to fulfill their balancing and congestion management needs [18]. A linear formulation for congestion management considering voltage

and reactive power was applied, which is able to accommodate LMPs and also Distribution Locational Marginal Pricings (DLMPs) [19]. The proposed market models are run after the day-ahead market, so the system operators can procure the necessary flexibility to solve imbalances and congestion resulting from the preliminary dispatch from EUPHEMIA (see section 6.3.1). This initiative is an example of how nodal prices could be implemented in a sequential market clearing integration scenario composed by, for example, a nodal flexibility market to manage congestion followed by the current balancing markets described in Section 6.3.3.

In addition, a study on the strategic behavior of flexibility service providers was also performed in [18], which demonstrated that, even with nodal prices, participants can "game" the flexibility markets. This means that market participants can bid higher than their marginal cost depending on the level of fragmentation of the market (i.e., if DSO and TSO markets are separated), the network topology, the grid constraints, and the number/placement of the providers within the systems. Although the study was performed in flexibility market models proposed in the context of the project, the results can be leveraged to other markets. For example, it supports the claim that a full nodal market clearing model, without redispatch, is better suited to avoid gaming, as the market is not fragmented and liquidity is increased.

7 Policy implications and discussion

In order to reach EU climate goals, a fully decarbonized electricity sector is a cornerstone to reach the overall net zero emission target in 2050, with recent research expecting the electricity sector to be already fully decarbonized and heavily relying on RES by 2040 [133]. For this to happen efficiently, European cooperation for network extension, as well as its efficient utilisation is needed [37], so that VRE and flexibility potentials can be matched within and across national borders (cf. Section 4).

At the same time, intra-zonal network congestion is increasing in several European member states, a challenge that will increase with the mandate of making 70 % of international interconnector capacity available to implicit market coupling.

This whitepaper can be seen as part of a series of whitepapers on electricity market design 2030 - 2050 [15, 14] and argues that the current zonal system is poorly prepared to meet the European challenges on the way to an integrated European and fully decarbonized electricity system. Building upon the insights of the previous two whitepapers that analyze the pros and cons of LMP in detail and also discuss a more fine granular temporal resolution complementing LMP, there are several policy conclusions to ensure that policy goals can efficiently be reached in Europe. One such conclusion is the transition to a regionally more fine granular market design, as it is better suited to reflect the scarce network capacities and, therefore, contributes to more efficient electricity market outcomes and dispatch. A nodal pricing system or LMP would fully consider all physical restrictions when the market clears, which is why node-specific prices reflect both local and temporal capacity-scarcity in form of price peaks. Thereby, a nodal system avoids costly redispatch and provides proper location-specific incentives for long-run investments. While the debate about abandoning uniform pricing is still ongoing in Germany, this whitepaper builds upon the insights of the preceeding two whitepapers and argues that the benefits of transitioning towards nodal prices quite likely outweigh the associated costs and challenges (e.g., transaction costs in the market design transition or concerns relating to low liquidity and market power), in particular for countries with high shares of intermittent VRE.

In that regard, countries with high shares of intermittent VRE like Germany may act as frontrunners and adjust market design to the new requirements of an VRE-based energy system. Other European countries that rely more on controllable and predictable energy sources like Norway (with high shares of hydro powered plants) and France (with high shares of nuclear power) may follow suit. Recent examples from the UK, however, show that also countries with high shares of controllable energy sources strive for the introduction of nodal pricing, whereby the energy regulator for the UK, Office of Gas & Electricity Markets (OFGEM), has launched a tender for design options for nodal pricing [126]. Also the UK system operator, National Grid ESO, is listing nodal pricing as one important option for future market design [118]. The recent strive for regionally more fine grained prices in some European countries allows for mutual learning effects on how to conduct the market design transition and avoid potential pitfalls like ex-post corrections in market design early on.

For those countries conducting the transition to nodal pricing, as argued in [15], there are several reasons why a shift to nodal pricing should be done in one step, rather than via sequential rezoning into smaller and smaller zones, when looked at from a national perspective. This is the case, as frequent rezoning may involve recurring political debates on the question where to draw zonal boundaries, frequent price adjustments resulting from different zonal designs, and generally increased uncertainty for market participants with respect to long-run investments. Moreover, with increasing feed-in by intermittent VRE, predicting congestion and, thus, defining "optimal" bidding zones gets increasingly difficult.

Summarizing, this whitepaper argues in favor of a nodal-pricing transition in European countries for the following reasons:

1. The current zonal systems with cost-based redispatch cannot effectively and efficiently include flexibility options with opportunity costs, such as demand response, batteries, and EVs, as no clear regulated cost-basis exists. In particular, marginal costs can only be determined very vaguely by third parties in the case of such flexibility options (either too small-scale assets or unknown opportunity costs in the

case of, e.g., load shifting).

2. Market-based redispatch leads to a mismatch of prices over time periods; as a result, the infamous inc-dec game occurs, when congestion can be anticipated [83].

3. The current European CACM regulation proposes rezoning when structural congestion changes. With the energy transition and high shares of VRE there are no stable zonal configurations [31]. Frequent rezoning (or smaller zones) leads to loss of liquidity especially in long-term markets, as the underlying reference price of these contracts frequently changes, thus corroding the trust that contracts are liquidly re-tradable in future, and as it makes establishing a liquid market for cross-zonal transmission rights challenging [108].

4. In contrast, nodal pricing systems have a coherent system of complementary short- and long-term markets to address liquidity concerns and locational price risks (financial transmission rights auctions combined with liquid forward trading hubs, with stable underlying prices, namely prices at physically defined network nodes at the transmission level). The preceeding two whitepapers [15, 14] provide a more detailed analysis of the characteristics of nodal pricing as well as a description of instruments like trading hubs and financial transmission rights to solve, e.g., concerns regarding low market liquidity, market power, price risks, and distributional effects.

Additional benefits of nodal pricing arise, when looking at European market integration, as with nodal pricing congestion may not only be managed efficiently within, but also across borders. Where do inefficiencies in cross-border trade arise in the current zonal-trading set-up? As no price is put on intra-zonal congestion (especially not dynamically over different points in time), there is an inherent ex-ante trade-off to be made between intra-zonal and cross-zonal transmission capacity. This is addressed by European minimum Remaining Available Margin (minRAM) rule, which states, that (partly in future) 70 % of transmission capacity of network elements needs to be made available for cross-zonal trade. In a static setting this parameter may be efficiently calibrated, however, as congestion varies over time, situations arise where either more capacity should have been made available for cross-zonal trade, as intra-zonal congestion is limited or vice-versa. Nodal pricing resolves this issue, as the distinction between cross-zonal and intra-zonal congestion is lifted, and made explicit in local time-varying power prices.

European countries and stakeholders in the electricity system should take concrete steps to prepare the introduction of nodal pricing. The next CACM bidding zone review may propose to split up existing zones with significant internal congestion. As detailed above, rezoning may be undesirable for several reasons, especially if such rezoning happens frequently, as can be expected in a European power system that fundamentally changes the location of where electricity is generated, and adds new demand via electrification over the next decades. Thus, the option should be given to member states to instead opt directly for the introduction of nodal pricing, which is robust to changing congestion conditions and in this way provides regulatory certainty. Several implementation options exist for a partial (via sequential or hybrid clearing mechanisms) or complete introduction of nodal prices in Europe. As detailed in Section 6.2.2, firstly, several of these options should be investigated in detail by developing commercial scale shadow solvers that can accommodate one to several member states switching to nodal pricing. Such shadow solvers could first be fed with historical data, and later be run in parallel to the existing market clearing, to investigate the technical and economic feasibility of different coupling approaches. The investment in such solvers can be considered quite small, as compared to the potential savings and benefits of the introduction of nodal pricing in Europe. Secondly, the legislative discussion and changes to regulation (cf. Section 6.2.2) necessary for the implementation of these options should already be started now.

Several other EU regulation reforms can be done now preceeding a switch to nodal pricing (and possibly in addition to a finer temporal granularity as discussed in the previous whitepapers), as they would be beneficial for European market integration in both zonal pricing and nodal pricing:

> The introduction of frequent intraday auctions, as already envisioned in the CACM regulation, as this more efficiently makes use of cross-border interconnection, than continuous trading.

> The harmonisation of bidding products in Euphemia to multi-part bids, to leverage market efficiency

improvements, as well as computational benefits.

> Introducing the co-optimisation of energy & ancillary services, as to decrease inefficiencies that result from sequential decision making of actors on whether to allocate resources to the wholesale market or to ancillary services.

> Reassessing and adjusting the MiFID II directive and national implementation to better enable a broader participation in financial trading for hedging purposes, which is necessary to build liquid long-term markets for nodal pricing (under requirements of prudent risk management, cf. [15] for an extended discussion).

> EU regulation needs to foster the deployment and use of digital technologies, for instance, in the current grid infrastructure ("smart grid") to provide real-time congestion data for nodal pricing or enable a more active role of electricity consumers in nodal markets to increase liquidity. Also, the development of a shadow solver – as described above – that runs in parallel to current zonal market clearing is an important step to prepare for the introduction of nodal pricing.

> Improve the technical, regulatory framework and market environment to ensure that a larger part of the flexibility resource potential becomes market-available (see Section 4, and Figure 6). For this an increased digitization effort notably in distribution grids combined with regulatory adjustments is needed to ensure that more of the in principal flexible assets such as heating and cooling appliances as well as electric cars are becoming controllable for operational flexibility use cases.

The European market integration can take an important next step, if congestion management is incorporated in the market structure, and electricity prices are not artificially set at a zonal, and in effect often national level, but at the local level, where they are physically and economically grounded.

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