Whitepaper

ELECTRICITY SPOT MARKET DESIGN 2030-2050

KOPERNIKUS PROJEKTE
SynErgie
Die Zukunft unserer Energie

GEFÖRDERT VOM

Bundesministerium für Bildung und Forschung

GEFÖRDERT VOM

Bundesministerium für Bildung und Forschung

KOPERNIKUS PROJEKTE

SynErgie

Die Zukunft unserer Energie

Electricity Spot Market Design 2030-2050

Corresponding authors:

Martin Bichler (Work Package Lead) and Hans Ulrich Buhl (Cluster Lead)

E-Mails: bichler@in.tum.de, hans-ulrich.buhl@fim-rc.de

List of authors:

Ashour Novirdoust, Amir[b]
Bichler, Martin[e]
Bojung, Caroline[c, d]
Buhl, Hans Ulrich[c]
Fridgen, Gilbert[c, d]
Gretschko, Vitali[f]
Hanny, Lisa[c]
Knörr, Johannes[e]
Maldonado, Felipe[e]
Neuhoff, Karsten[a]
Neumann, Christoph[*]
Ott, Marion[f]
Richstein, Jörn C.[a]
Rinck, Maximilian[*]
Schöpf, Michael[c, d]
Schott, Paul[c]
Sitzmann, Amelie[b]
Wagner, Johannes[b]
Wagner, Jonathan[c]
Weibelzahl, Martin[c]

DIW BERLIN

[a]DIW Berlin – German Institute for Economic Research

ewi Institute of Energy Economics at the University of Cologne

[b]Institute of Energy Economics at the University of Cologne (EWI)

fim Research Center Finance & Information Management

Fraunhofer FIT Project Group Business & Information Systems Engineering

[c]Research Center Finance & Information Management and
Project Group Business & Information Systems Engineering (FIM/FIT)

uni.lu | SnT

[d]SnT - Interdisciplinary Center for Security, Reliability and Trust,
University of Luxembourg, Luxembourg

TUM

[e]Technical University of Munich

ZEW

[f]ZEW – Leibniz Centre for European Economic Research

Recommended citation:

Ashour Novirdoust, A., Bichler, M., Bojung, C., Buhl, H. U., Fridgen, G., Gretschko, V., Hanny, L., Knörr, J., Maldonado, F., Neuhoff, K., Neumann, C., Ott, M., Richstein, J. C., Rinck, M., Schöpf, M., Schott, P., Sitzmann, A., Wagner, J., Weibelzahl, M., 2021, Electricity Spot Market Design 2030-2050, https://doi.org/10.24406/fit-n-621457.

[*]Independent Author

DOI: 10.24406/fit-n-621457
https://doi.org/10.24406/fit-n-621457

GEFÖRDERT VOM

Bundesministerium für Bildung und Forschung

KOPERNIKUS PROJEKTE SynErgie Die Zukunft unserer Energie

Preamble

Driven by the climate conference in Paris in December 2015 countries worldwide are confronted with the question of how to shape their power system and how to establish alternative technologies to reduce harmful CO_2 emissions. The German government plans that even before the year 2050, all electricity generated and consumed in Germany should be greenhouse gas neutral [1]. To successfully integrate renewable energies, a future energy system must be able to handle the intermittent nature of renewable energy sources such as wind and solar.

One important means to address such electricity production variability is demand-side flexibility. Here, industry plays a major role in responding to variable electricity supply with adequate flexibility. This is where the Kopernikus project SynErgie comes in with more than 80 project partners from academia, industry, governmental, and non-governmental organizations as well as energy suppliers and network operators. The Kopernikus project SynErgie investigates how to best leverage demand-side flexibility in the German industry.

The current electricity market design in Germany is not well suited to deal with increasing levels of renewable energy, and it does not embrace demand-side flexibility. Almost 6 GW of curtailed power in 2019 provide evidence that changes are needed with respect to the rules governing electricity markets. These rules were designed at a time when electricity generation was concentrated on a few large and dispatchable conventional power plants and demand was considered inelastic.

The SynErgie Cluster IV investigates how a future-proof electricity market design should be organized. The corresponding Work Package IV.3.1 more specifically deals with analyzing and designing allocation and pricing rules on electricity spot markets. The resulting design must be well suited to accommodate demand-side flexibility and address the intermittent nature of important renewable energy sources. This whitepaper is the result of a fruitful collaboration among the partners involved in SynErgie Cluster IV which include Germany's leading research organizations and practitioners in the field. The collaboration led to an expert workshop in October 2020 with participation from a number of international energy market experts such as Mette Bjørndal (NHH), Endre Bjørndal (NHH), Peter Cramton (University of Maryland and University of Cologne), and Raphael Heffron (University of Dundee). The whitepaper details the key recommendations from this workshop.

In particular, the whitepaper recommends a move to a locational, marginal price-based system together with new bidding formats allowing to better express flexibility. We argue in favor of a one-step introduction of locational, marginal prices instead of repeatedly splitting existing zones. Frequent zone splitting involves recurring political debates as well as short- and long-run instabilities affecting the basis for financial contracts, for example. Importantly, the definition of stable prize zones is very challenging with increasing levels of distributed and renewable energy sources. The recommendation is the outcome of an intense debate about advantages and downsides of different policy alternatives. However, such a transition to locational, marginal prices is not without challenges, and it is a call to arms for the research community, policymakers, and practitioners to develop concepts on how to best facilitate the transition and ensure a reliable and efficient electricity market of the future.

We'd like to thank all the project partners and are grateful for the financial support from the Federal Ministry of Education and Research as well as the Project Management Jülich.

Hans Ulrich Buhl (Cluster Lead)
Martin Bichler (Work Package Lead)

GEFÖRDERT VOM

Bundesministerium
für Bildung
und Forschung

Contents

List of Figures

List of Tables

Acronyms

AC	Alternating Current
aFRR	Automatic Frequency Restoration Reserve
AI	Artificial Intelligence
APIs	Application programming interfaces
ARR	Auction Revenue Right
CAISO	California Independent System Operator
CfD	Contract for Difference
CH	Convex Hull
DC	Direct Current
DLT	Distributed Ledger Technologies
DSO	Distribution System Operator
EEX	European Energy Exchange
ELMP	Extended Locational Marginal Price
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
ERCOT	Electric Reliability Council of Texas
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FCR	Frequency Containment Reserves
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Right
HVDC	High Voltage Direct Current
IC	Integrated Circuit
ICE	Intercontinental Exchange
Inc-Dec	Increase-Decrease
IP	Integer Programming
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
LCOS	Levelized Cost of Storage
LD	Lagrangian Dual
LMP	Locational Marginal Price
mFRR	Manual Frequency Restoration Reserve
MiFID II	Markets in Financial Instruments Derivative II
minRAM	Minimum Remaining Available Margins

MISO	Midcontinent Independent System Operator
NEMO	Nominated Electricity Market Operator
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
OMIE	Operador do Mercado Ibérico de Energia
PJM	Pennsylvania-New Jersey-Maryland Interconnection
RES	Renewable Energy Sources
SIDC	Single Intraday Coupling
SPP	Southwest Power Pool
TSO	Transmission System Operator
UCED	Unit Commitment and Economic Dispatch
UK	United Kingdom
US	United States
XBID	Cross-Border Intraday

KOPERNIKUS
SynErgie PROJEKTE
Die Zukunft unserer Energie

GEFÖRDERT VOM
Bundesministerium
für Bildung
und Forschung

1 Introduction

In the course of the energy transition, electricity systems are facing the challenge of reducing harmful CO_2 emissions by integrating large shares of typically variable and decentralized Renewable Energy Sources (RES). This calls for significant changes with respect to the transmission and distribution networks as well as the rules governing electricity markets, which were designed at a time when electricity generation was concentrated at comparatively few and dispatchable conventional power plants with large generating capacities.

To meet the new system requirements, research quite naturally aims for technical innovations in mostly engineering-oriented areas like electricity generation, transmission, or storage. For instance, on the generation side, nuclear power or coal plants are increasingly replaced by wind, solar, or hydro power technologies. On the transmission level, the High Voltage Direct Current (HVDC) technology may considerably reduce transmission losses over larger distances. Recent developments with respect to storage technologies suggest that electrochemical storage, in particular battery solutions, can be expected to drastically grow in capacity and contribute to balancing demand and supply.

In addition to engineering-driven changes, energy systems are also affected by recent advances with respect to digital technologies, being enabled by developments in both hardware and software components. More precisely, improvements in hardware lead to an increase in data transmission and processing speed as well as in overall IT presence, due to miniaturization and cost reductions. Sophisticated software applications further support automated and autonomous decision making by software agents as well as resilience, security, and enhanced encryption technologies. Building on these developments, digital technologies encompass, e.g., data analytics and machine learning, the Internet of Things, digital platforms, agent-based systems, or distributed ledger technologies. Corresponding applications are fast(er) and thereby enable automated electricity trading or autonomous learning for more accurate forecasts of, e.g., load profiles or RES generation. Moreover, electricity-generation capacities can be used more efficiently. Digital technologies may also contribute to the marketing of flexibility – the ability to balance fluctuating supply of renewables and electricity demand – on a regionally and temporally more fine-grained basis.

Taking current challenges and technological opportunities into account, a future-proof market design must bridge the new system requirements associated with an increasing share of variable renewables. This implies that market design decisions need to account for technological change in a forward-looking manner. Against this background, this whitepaper discusses main elements of a future market design 2030-2050 and necessary regulatory changes to realize benefits of both digital and energy technologies, with the aim of fostering a successful energy transition.

In order to address these issues, the whitepaper proceeds as follows: Section 2 summarizes key challenges of current electricity systems. Section 3 then provides an overview of both energy and digital technologies, taking the most relevant technological changes into account. The following Sections 4 and 5 are entirely dedicated to electricity market design, which is needed to set appropriate economic signals and incentives for market participants to use the available technologies in a way that contributes to tackling current challenges in the electricity system. In particular, Section 4 adopts an international perspective with real-world examples of different market designs with varying degrees of market liberalization. Section 4 also describes the typical time sequence of electricity markets, ranging from long-term oriented futures markets to more short-term oriented day-ahead, intraday and real-time markets. This section also outlines the typically needed corrective measures in the very short term (e.g., redispatch activities, feed-in management, and balancing power). Section 5 then delves deeper into concrete market design options and focuses on rules for allocation and pricing. In particular, it provides a discussion of the pros and cons of locational marginal prices, and it outlines the fundamentals of pricing rules for electricity markets. Section 6 elaborates on consequences of specific market design choices on market participants' incentives and strategic interaction. It focuses on long-run investment signals, market power as well as market manipulation in the form of strategic bidding or gaming. Finally, Sections 7 and 8 present a thorough discussion of main policy implications and directions for future research, respectively.

2 Challenges in current and future electricity systems

The electricity system in Germany (and Europe) is facing several current and future challenges, driven by the ongoing shift towards a variable renewable dominated electricity generation, the increase of distributed RES, as well as new and active types of electricity consumers, such as (newly) electrified industrial processes, electric vehicles, and heat pumps. In particular, **information technologies** (see Section 3) enable the shift towards such an electricity system. This section discusses several of the key challenges that are currently present or arising.

First, due to the technical need to constantly match demand and supply in electricity systems, a key challenge has always been to do so in the most economically efficient way, while respecting the security constraints that are necessary to keep the system from blacking out. Currently, this challenge has become more pressing with new **energy technologies**, the increasingly intermittent supply from RES, and the reduction of dispatchable power plants (see Section 3). In the future, intermittent generation will further expand, as well as new flexible demand from electrified processes (both from the industrial sector and households), and other sector-coupled processes. Thus, the underlying challenge evolves from matching few large power plants with a largely inflexible demand to an effective coordination of intermittent RES with different storage and demand-side flexibility options. New information technologies may assist in the matching process.

Coordinating such assets effectively is an optimization challenge under uncertainty. Market participants with storage and demand-side flexibility options face opportunity costs that the market typically cannot observe. In particular, constraints outside the electricity sector often influence the opportunity costs of, e.g., flexible loads. For instance, a factory can only increase (or decrease) its load if the production schedule allows to do so; this schedule may, in turn, depend on the schedule of the factory's suppliers, among others. From the market perspective, fully observing these constraints is practically impossible, causing information asymmetries between the market and operators of, e.g., storage and demand-side flexibility options. Against this background, efficient price signals based on an **expression of opportunity costs** are needed to coordinate many market parties, as these signals allow market participants to align their decisions with what is efficient (i.e., internalizing all relevant externalities) for the overall system and to form expectations with regard to how their actions will affect the system in future (see Section 5).

Second, the electricity system needs to avoid the violation of network constraints, that is, the limits of the power lines to transmit and distribute electricity. This is closely related to the first challenge of matching demand and supply, because in cases where transmission capacity is limited, demand and supply need to be matched locally, adjusted, or shifted over time. Currently, as electricity prices are mainly uniform prices within countries (i.e., a single wholesale market price – which does not reflect all transmission constraints – for one country/market area such as Germany/Luxembourg), situations of **network congestion** imply that market results need to be adjusted after trading via redispatch of conventional plants and feed-in management of renewable plants to meet the physical realities of the location of demand and generation and the limits of the grid (see Section 4). As generation has become more intermittent and more decentralized with the advent of RES, the costs for such measures have increased from roughly 600 million EUR in 2016 to almost 1 billion in 2019 [3]. In the future, while network investments are expected to increase, investments will probably not take place at the same scale and speed as the increase in peak demand and the connected generation capacity [4]. Thus, network congestion will probably further increase in the future, which increases the need to match demand and supply locally. Here, corresponding incentives will have to be set cross-sectoral, e.g., future e-mobility will have to adapt electricity demand according to current RES generation using modern communication and automated control technologies. Furthermore, cost-based redispatch, critically relying on the cost transparency of large power plants, will be challenging to implement with increasing numbers of opportunity-cost based consumption and storage options. Here, information technologies may help to increase the cost transparency of assets in the energy system. Market-based redispatch instead suffers from the infamous inc-dec **gaming**, i.e., incentives for participants to change their consumption and generation behavior to aggravate congestion and to profit from price differences between consecutive energy markets (see Section 6).

Third, a current challenge is the efficient utilization of cross-border interconnection capacity and its trade-off with network congestions (these are lower with higher investments in grids). The cross-border interconnection capacity also affects the resulting redispatch within the **sequential market structure** in countries (see Section 4). This has become more pressing with the European Union (EU) requirement (i.e., EU Regulation 2019/943 [5]) to make 70 % of interconnection capacity available to the markets (also referred to as the Minimum Remaining Available Margins (minRAM) requirement). In the future, this challenge becomes even more relevant, because the capacity to efficiently utilize flows between different regions allows for the geographic smoothing of demand and supply fluctuations, i.e., the smoothing of differences in consumption and (renewable) production at the same time (e.g., while the sun may be shining in Italy, it may be cloudy in Germany).

Fourth, the market design should mitigate **market power** and enable competitive markets with proper incentives (see Section 6). For instance, some current short-time pricing mechanisms create monetary incentives for market participants to behave contrary to system needs, because the prices do not reflect the marginal impact on the system, e.g., due to a lack of local differentiation or due to unjustified price differences between interconnected markets. This mismatch is currently countered by legal requirements to stick to schedules committed to the balancing responsible party, regardless of the monetary incentives of the market participants. In the future, this conflict will further increase, as congestions and the need for short-term adjustments become even more important.

Fifth, the relatively flat spot market price currently limits the incentives both for flexibility and for hedging deviations from standardized base load and peak load contracts, since there are few price peaks (and periods of low prices) to profit from as a flexibility provider or to hedge against. In the future, increasingly volatile (local) power prices require new hedging products (i) to secure revenue streams for flexibility options and (ii) to avoid power price risks for energy users. **Efficient prices** should set proper incentives, account for opportunity costs of market participants, and support a welfare-maximizing dispatch (see Section 5).

And sixth, currently the scale of investments in renewable technologies is partially limited due to the uncertainty on contracting and financing provisions, and the system value of different technologies is only partly represented in their remuneration. In the future, short-term markets and long-term hedging policies will be needed to set system-beneficial **investment incentives** for RES (see Section 6).

The following sections address these elements in greater detail. Table 1 summarizes key challenges and refers to the corresponding sections of this whitepaper.

Table 1: Overview of challenges

Challenge	Section
New energy technologies and market participants	3
Digital transformation and information technologies	3
Design of a sequential and cross-border market structure	4
System imbalances and network congestions	4
Expression of opportunity costs for efficient dispatch	5
Efficient price signals	5
Investment incentives for RES	6
Market power mitigation	6
Gaming and efficient redispatch	6

3 Technology and technological changes

Technologies and corresponding technological changes can be both a challenge and an opportunity for electricity market design. For instance, renewable generation allows for electricity production at almost zero marginal cost, but at the same time creates additional challenges in form of increased supply (and price) volatility as well as a growing distance between generation facilities and demand centers at the aggregated macro-level of energy systems. Quite similarly, the advent of new digital technologies and their application to electricity systems not only create new opportunities in terms of analyzing and forecasting, e.g., load profiles, but also raise concerns regarding information technology security and privacy in the absence of suitable information technology concepts and standards. Against this background, this section aims to provide a detailed overview of energy and information technologies that need to be considered in modern electricity market design in order to make best use of their potentials from an electricity system perspective. This especially includes a need for market designers to be aware of and consider recent technological advances when devising new market rules.

3.1 Energy technologies

In recent years, a fundamental shift from a centralized system with a top-down energy flow to a system with a multitude of decentralized sources of renewables has affected electricity markets. This shift stems, among others, from policy-induced changes in the deployment of technologies and associated technological and cost developments, and is accompanied by new grid technologies tackling an increasing number of bidirectional flows. Electricity storage and demand may provide the necessary flexibility to meet the intermittent electricity supply and contribute to a stable grid operation. The following sections describe key energy technologies, which are subdivided in grid, generation, storage, and demand technologies, and highlight the main market design implications.

3.1.1 Grid technologies

Two major developments have affected grid technologies in the past decades. First, the improvement of power electronics and transformers enable an efficient conversion between different power voltage levels also for Direct Current (DC). This provides the basis for the development of the HVDC transmission technology, which allows to cover longer transmission distances compared to Alternating Current (AC) technologies. In addition, DC constitutes a frequently used technology at the low-voltage level and in local grids behind the meter [6]. This allows for an easier integration and interaction of distributed energy resources like photovoltaics or batteries and therefore an increased efficiency at the low-voltage level.

Second, high-temperature superconductors have emerged, which are materials with a zero electrical resistance under low surrounding temperatures [7]. These materials might be able to enhance grid capacities in the future, especially in urban areas, as they require less space for cables and enable longer HVDC connections with high current carrying capacities [8]. Electricity market design may account for this by considering future scenarios with less transmission losses and a higher grid capacity.

3.1.2 Generation technologies

Generation technologies represent the supply side of electricity markets and need to reliably serve consumer demand. For many years, thermal power plants, which operate mainly based on the combustion of fossil fuels or on nuclear power, have served that purpose. Thereby, the underlying production process rests on thermal engines that convert thermal power into mechanical force and, ultimately, electricity. Large thermal power plants usually have long construction and building periods, require high investments, and need to operate for decades to reimburse their investments. Reimbursements stem from selling the generated electricity on various electricity markets, while electricity generation is, to a high degree, independent of changing weather conditions. Traditionally, fossil fueled or nuclear power plants serve as base load, shoulder load, as well as peak load generators. However, base loads plants exhibit rather little flexibility, as ramping up or down these plants is usually time- and resource-consuming. Moreover, these plants usually face a minimum load level, making electricity generation economically unattractive below a certain quantity threshold. Furthermore, base load plants quite often exhibit maximum power gradients or ramping limits, meaning maximum changes in output in a given time period, as well as different start-up times for cold or warm starts. This implies that thermal plants cannot arbitrarily react to short-term changes in market conditions and mainly serve as steady base load facilities that come with certain costs. In contrast to that, it is predominantly gas- or hard coal-powered plants that currently carry out short-term adjustments in the German electricity system. However, given the aforementioned technical constraints, in the case of coal-powered plants this is a misuse that may generally be associated with wear and tear on the plants.

In the course of the energy transition, renewable energy technologies, as, for example, wind, solar, hydro, or biomass are gaining increasing importance, providing an environmentally friendly alternative to thermal power plants. However, this technological shift away from fossil fuels and nuclear power brings about fundamental changes concerning, e.g., generation cost structures, dispatchability, and the need for additional inter-regional transmission services. For instance, once installed, wind, solar, and hydro plants can operate at almost zero marginal cost, leading to a decline in electricity prices in periods with significant infeed of renewables. The cost structure for biomass strongly depends on the employed substrate and the preprocessing. However, electricity generation from wind and solar is highly intermittent and dependent on uncertain weather conditions. As a consequence, their controllability is limited to the dispatch between zero (curtailment) and the weather-dependent, varying maximum output at a certain point in time.

In comparison, hydropower and some biomass technologies provide at least some degree of two-sided flexibility (i.e., up- and down-regulation), as they are characterized by short ramping and start-up times. While some biomass technologies are flexible to a certain degree, others are not due to limited intermediate storage. This issue can, however, be solved by complementing such biomass technologies by local gas storage. Similar to wind and solar, hydro technologies such as run-of-river are intermittent and dependent on the water level, but exhibit a more stable upper limit. Furthermore, hydro technologies are usually bound to certain geographical regions and may thus require long-haul transmission and grid extensions. Similar concerns arise with respect to huge offshore wind parks, which are usually located far away from demand centers.

3.1.3 Electricity storage technologies

Quite generally, energy storage shifts the delivery time of electricity. More recently, energy storage has gained increasing attention, due to advances in storage technologies like batteries, and the growing share of intermittent renewables. Further examples for different storage technologies are pumped hydropower energy storage, compressed air, flywheels, superconducting magnets, or supercapacitors. Each of these technologies has advantages either regarding the capability to absorb, respectively to provide power (specific power measured with W/kg) or the ability to store energy (specific energy in Wh/kg). Koohi-Fayegh and Rosen [9] provide a comprehensive overview on the state-of-the art storage technologies.

Hydro technologies that have gained special importance are pumped storage facilities or hydroelectric reservoirs, as they may provide electricity storage in addition to generating electricity. Pumped hydropower, for instance, achieves the lowest Levelized Cost of Storage (LCOS) among competing storage technologies. LCOS refers to the total lifetime cost of the investment in an electricity storage technology divided by its cumulative delivered electricity [10]. The low LCOS result in significant cost advantages for pumped hydropower storage, as compared to more recent storage technologies like, e.g., battery solutions. Additionally, pumped hydro storage technologies exhibit better properties concerning storage capacities and lifetimes. However, pumped hydro storage also has some drawbacks with respect to start-up and ramping constraints, leading to efficiency losses compared to, e.g., battery solutions. In addition, pumped hydropower is constrained by the availability of natural resources.

Battery solutions, or electrochemical storage in general, are likely to grow in capacity in the near future. Concerning different battery technologies, there are different advantages and disadvantages: For example, redox flow batteries allow flexible layouts and long lifetimes, while charging and discharging rates cannot yet compete with alternative storage technologies such as lithium-ion batteries. The latter, in contrast, display a high round-trip efficiency, as they exhibit little self-discharge. Overall, battery systems are still very expensive, but are expected to become less expensive in the future [11]. The overall high efficiency constitutes a major argument in favor of electrochemical storage solutions. Full capacity storage, however, is only feasible for a limited time period, unlike weekly (or even monthly) storage cycles for pumped hydropower storage, qualifying them mainly as primary control reserves.

While pumped hydropower storage and batteries are probably the most widespread storage technologies, some further developments are worth mentioning. For instance, pumped heat storage is an established concept, which allows to store heat as molten salt. Compressed air technologies are also quite mature, but still exhibit significant start-up costs as well as a low efficiency in reconverting electricity. Supercapacitors exhibit quick response and long lifetimes, but are limited in their storage time. Flywheels also possess quick response times and are frequently employed as primary reserves.

3.1.4 Sector coupling

Besides batteries and other electrical energy storage technologies that are able to return the stored energy as electricity back to the grid, Power-to-X technologies may also convert electricity into other energy carriers. This cross-sectoral transformation enables to store electricity in gas like hydrogen and to further process the hydrogen into other energy carriers. The term "sector coupling" describes this linkage of different energy carriers like, e.g., gas, heat or liquids, and therefore of different energy sectors. The energy carrier generated from electricity with Power-to-X technologies can then either be transformed back to electricity (e.g., with fuel cells transforming hydrogen to electricity) or be used directly (e.g., by the combustion of synthetic Power-to-X-based fuels). Considering sector coupling from a holistic view, also energy-intensive products like paper pulp or aluminum may serve as means of energy storage and may balance power between different sectors as well as allow to transport energy over larger geographical distances [12]. These circumstances have implications for the market design: it must also take the potentials of other sectors into account, in terms of providing temporal balancing and transporting energy. This also involves an assessment of how different sectors can contribute to electricity market objectives and to creating the right incentives for the development of an adequate infrastructure.

From an electricity market perspective, both electricity storage and sector coupling resources may fulfill a dual role as both electricity producers and consumers. As a result, the term "prosumer" has emerged in recent years, referring to market participants and technologies that simultaneously exhibit supply and demand characteristics. In this context, storage technologies may not only provide flexibilities on the supply side, but also on the demand side. In the following, demand-side flexibilities will be discussed in light of technological developments.

3.1.5 Electricity demand

In the past, electricity demand was mainly inflexible. As there has not been a regular, intensive information exchange between electricity suppliers and consumers (often only once a year for billing), the electricity generation has been congruent to (standard) load profiles, which described the consumption behavior of different electricity consumer groups during a day.

Introducing the concept of demand-side management, research made first efforts to make electricity demand flexible in the late 1970s [13]. Researchers first used the concept of demand-side management from the perspective of a utility that is able to exert a certain control on consumer loads with the aim to, e.g., avoid capital-intensive investment in grid or generation capacity. Electricity consumers that curtailed their loads and, in this way, provided flexibility based on corresponding signals of their utility were able to reduce their electricity bill. The underlying technology was fairly simple, as it only required a one-way communication from the utility to the consumers. The liberalization of the electricity markets in many countries offered the opportunity to provide and actively market demand-side flexibilities. At least in theory, it was now possible for electricity consumers on electricity markets to benefit from price fluctuations. Today, however, it is predominantly large consumers that react to market prices [14]. Besides trading on electricity markets, large consumers are nowadays also allowed to take part in the market for ancillary services. Nevertheless, more sophisticated information technology with a measurement of electricity consumption at a frequency of at least a quarter of an hour is necessary.

However, it is important to note that demand flexibility comes at certain costs and is characterized by different restrictions [15]. For instance, certain home appliances or industrial core processes may not be interrupted or delayed without significant losses in utility or product quality [16]. Focusing on industrial demand flexibility, a temporal shift of production processes may cause rescheduling costs as well as production inefficiencies. These inefficiencies may then, for example, translate into higher costs for fuel, labor or maintenance. Moreover, upfront investments may be necessary to allow for such flexibility in the first place including, e.g., technological adjustments of production facilities and machines or introduction of intermediate product storage.

To exploit demand-side flexibilities also on a smaller scale and to better integrate the demand side into the future electricity system, the introduction of smart meters, but also other smart devices, is an important step for enabling intelligent technologies for electricity demand. Thus, this technology creates a link between the energy technologies and the information technologies, which will be described in the next section.

3.2 Information technologies

Information technologies have a widespread impact on modern societies. Among others, the ongoing digitalization has the potential to reshape essential characteristics of energy markets. The following sections will discuss recent technological advances and applications for electricity systems.

3.2.1 Technological developments

The past decades have seen major developments in information technologies, which have been mainly fueled by a decrease in sizes and costs of hardware as well as a significant increase in the speed of data transmission and processing. For example, the number of transistors on an Integrated Circuit (IC) has doubled roughly every two years from around 1970 onwards [17] – with roughly 2,500 transistors on an IC in 1970 to almost 50 billion in 2020 [18]. This development, famously captured by the term “Moore’s law” [19, 20], is only one example among many, illustrating how fast information technologies have developed over the past decades. To give another example, today every smartphone has more computing power (at lower cost) than the mainframe computer that was used in 1969 to safely bring the astronauts Armstrong, Aldrin, and Collins to the moon and back [21].

In the electricity system, both hardware and software have evolved along with developments in market design. For example, utilities used early mainframe computers with corresponding software to run energy management systems that would allow them to calculate optimal power flows, thereby assisting utility operators in their task of keeping the electricity grid balanced [22]. With modern hardware and software one can control and monitor almost all areas of the electricity system [23].

Recently, more advanced information technologies emerged such as platforms, distributed database technologies like blockchain, or data analytics. The advances in hardware and software described above served as enablers for these new information technologies. In electricity markets, information technologies not only promise to lower transaction costs by enabling greater participation of market players or reducing information costs, but more importantly information technologies allow for completely new ways of organizing the electricity market.

To better understand the role information technologies can play in the electricity market design by 2030-2050, information technologies and their respective potentials for market design will be discussed. First, nine generic classes of information technologies are derived and explained to provide an overview of the wide range of existing information technologies. Second, possible technological development trends are examined for the nine classes of information technologies. Finally, the main potentials of information technologies for electricity market design are identified, including increasing the transparency in the electricity system, enabling more efficient knowledge-sharing, and increasing the automation in the electricity system.

3.2.2 Nine classes of information technologies

Today, a wide range of information technologies exist, whereby 29 prominent examples ranging from, e.g., DNA Computing, Artificial Intelligence (AI) to Carbon-Based Transistors are displayed in the Gartner Hype Cycle for Emerging Technologies [24]. The many different information technologies may be sorted into classes that have been validated in a workshop with eleven experts in the field of information technologies and information systems. This allows to structure the existing technologies and to determine their potential more accurately. Literature provides various classifications of information technologies (see, e.g., [25, 26, 27]). However, the existing classifications are either too narrow or too broad in the number of information technologies they cover. For example, [27] present a classification that is too narrow for the purposes of this contribution, because it does not consider, e.g., Distributed Ledger Technologies (DLT). Recent literature indicates, however, that DLT such as blockchain can play a major role in the design of future electricity markets (see, e.g., [28, 29, 30]). Pousttchi et al. [31] create a classification with as many as 22 different information technology classes that is too broad for the purposes of this paper since it covers technologies that are not considered relevant for the design of electricity markets such as, e.g., brain-computer interface or implants. Therefore, based on the experts' judgment, a new classification was derived by classifying the most prominent information technologies into a matrix along two axes: On the horizontal axis of this matrix, the technologies are classified according to what using them can achieve, where it is distinguished between (user) interaction, data collection (and generation), data transmission, data processing, and data storage. On the vertical axis, the technologies are classified according to whether they predominantly allow to receive signals, allow to generate data, allow to generate information, or allow to generate knowledge. Organizing the various information technologies in such matrix allows to identify nine generic classes of information technologies (see Figure 1): sensor technologies, data transmission technologies, cloud technologies and high-performance computing, database technologies, data analytics, AI, digital platforms, interfaces, and the overarching field of safety, security, and privacy. Note that safety, security, and privacy are illustrated differently in Figure 1 than the other eight technology classes. This is because information technologies across all classes face the overarching goal of maintaining and promoting safety, security and privacy.

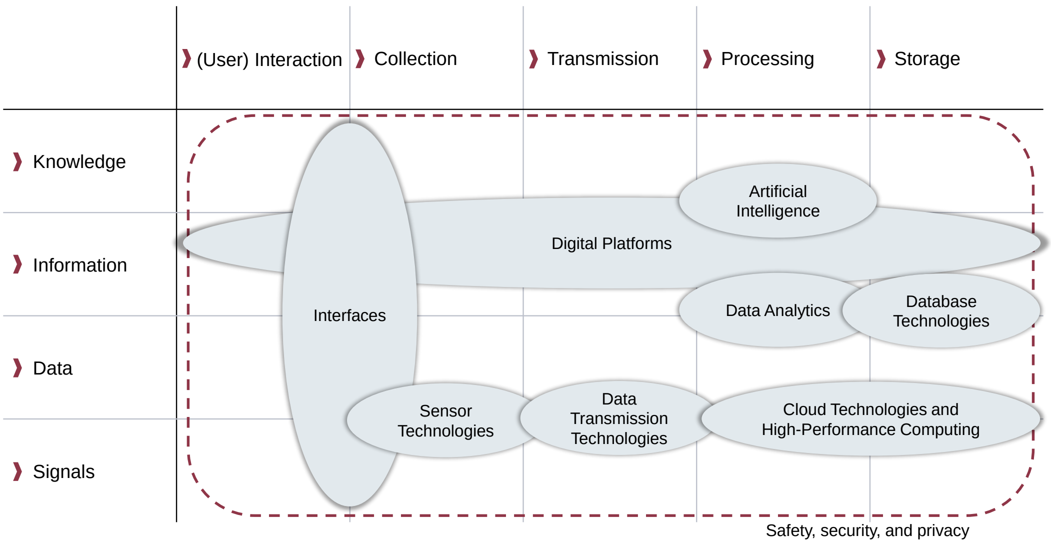


Figure 1: Classification of information technologies along two axes

Each of the nine classes of information technologies generally delivers a specific function. For example, in the context of electricity systems, sensor technologies can convert temperature measurements into electrical signals; the respective data helps, for example, assessing the conductivity of a transmission line. Table 2 summarizes the nine classes of information technologies with their specific functions, exemplary technologies, and possible technological development trends. The latter is of high importance: In terms of electricity market design for 2030-2050, market designers should anticipate today as to what the information technologies available by that time will be capable of from a technological point of view. For instance, while certain high-performance computing technologies may be too costly for a broad application in the electricity system today, they may be affordable for many more market players in ten years from now due to considerable cost reduction.

Table 2: Characteristics of the nine classes of information technologies

Class	Function	Exemplary technologies	Possible technological development trends
Sensor technologies	Convert physical or geometrical measurements into electrical signals from which data may be generated	GPS, gyroscope	Cost reduction [32], miniaturization, reduction of error susceptibility, increase of signal processing [33]
Data transmission technologies	Transport data from a sender to one or more recipients	5G, Bluetooth	Cost reduction, increase in data rate [34], reduction of latency
Cloud technologies and high-performance computing	Process data and perform complex calculations at high speed	Edge computing, grid computing	Cost reduction, performance improvement [35]
Database technologies	Collect, manage, and access data in an organized way	DLT, in-memory database	Cost reduction, performance improvement [36]
Data analytics	Extract information from data with the help of statistical methods	Big data, predictive analytics	Automation [37]
AI	Interpret external data correctly, learn based on it and flexibly achieve specific goals and tasks through these learnings	Machine learning, deep learning	Automation, reduction of error susceptibility [38]
Digital platforms	Provide the infrastructure to link two or more (groups of) actors with each other, e.g., customers, suppliers, users, or service providers	Trading platform, brokerage platform	Cost reduction, increase of automation, increase of standardization [39]
Interfaces	Facilitate more efficient interaction between machines, programs, and between humans and machines	Application programming interfaces (APIs), smart speaker, gesture control	Cost reduction, reduction of error susceptibility, automation [40, 34]
Safety, security, and privacy	Safeguard against malfunction and protect against attacks on confidentiality, integrity, data, and information	Unified endpoint security, secure access service edge	Cost reduction, performance improvement

3.2.3 Impact of information technologies on electricity systems

The nine classes of information technologies are important components of the future electricity market that market designers should use sensibly. Each class of information technologies can have specific impacts on the electricity system. This section, however, focuses on three major impacts of information technologies on electricity systems identified in the literature (see, e.g., [41, 42]): (1) information technologies increase the availability of information and therefore the transparency in the electricity system, e.g., with respect to the state of a power plant or the availability of demand-side flexibility from behind-the-meter-assets like heat pumps; (2) information technologies enable more efficient knowledge-sharing, e.g., with the use of platforms; (3) information technologies enable increased automation of the electricity system, e.g., when autonomous software agents trade on the spot market on behalf of human market players. Subsequently, these three impacts are described in more detail.

First, information technologies help collecting information about the electricity system in order to gain insight into its current state. Thereby information technologies increase the transparency about the state of the grid, the electricity market and all other components of the electricity system. For example, sensor technologies allow to collect raw data on the temperature of transmission lines, which network operators can use to determine network utilization more precisely – generally speaking, the lower the outside temperature at a transmission line, the more electricity this line can conduct. Market players can use data transmission technologies to transmit the data from the place of collection in near real-time. They can then use the data to evaluate the state of the system and make decisions accordingly. Employing cloud- and high-performance computing and data analytics makes it possible to convert raw data into information, again increasing the transparency of the system since this supports an interpretation of the current state based on processed data. Data collection and processing, as described above, are certainly not new and have been common practice in the context of electricity systems for a long time. However, information technologies promise that the extent of data collection will further increase in the coming decades, leading to higher transparency. From the perspective of electricity markets, the effect of increased transparency is twofold: On the one hand, transparency may enhance market efficiency, as it increases available market information and allows for informed decision-making as well as reliable future expectations concerning, e.g., return on investment. On the other hand, transparency allows to effectively monitor the behavior of competitors and, thus, may foster strategic coalitions and market concentration, which may ultimately lead to market distortions. Which of these two effects actually prevails in practice hinges, among others, on the specifications of a given electricity market design.

Second, information technologies help participants in the electricity system to create knowledge faster and to share it easier. One definition describes knowledge as the application and the productive use of information, involving a certain understanding or awareness [43]. Technologies like AI can therefore take an important role in the generation of knowledge out of the ever-increasing amount of data and information generated, transmitted, and processed by sensor, transmission, computing and analytics technologies. Examples for the generation of knowledge by the use of AI in the electricity system are the design of pricing mechanisms and incentive schemes for demand response as well as the customer segmentation in the electricity system depending on the specific loads of the individual consumers [44]. Besides the generation of knowledge, information technologies also largely contribute to the sharing and exchange of knowledge. During the last decade, especially cloud computing and digital platforms have gained importance, lowering the access barriers to knowledge [45]. For instance, energy-intensive industries may share their internal knowledge on flexible production processes with network operators or aggregators to (profitably) market their flexibilities. Still, especially taking into account platform-inherent characteristics like, for example, network effects or economies of scale and scope, concerns arise with respect to market concentration and the evolution of a winner-takes-all marketplace. Hence, it gets increasingly difficult for new entrants to compete with incumbent platforms due to, for example, a lack of accumulated electricity market data or knowledge. As a result, digital platforms require active market design interventions, e.g., in the form of adjustments to the regulatory framework. More recently, blockchain is tested in the energy sector for sharing information and knowledge among parties that do not necessarily know each other trustworthy and tamper-proof. Although blockchain may generally consume more electricity than centralized database technologies, the electricity consumption of blockchain is by far not as high as often claimed. Moreover, blockchain helps digitizing processes that centralized database technologies cannot digitize. This may even save more electricity than blockchain consumes [46].

Third, information technologies allow an increased automation of electricity systems, leading to, e.g., automated decision-making and trading on electricity or flexibility markets. To take up the example from above, information technologies will allow to collect raw data via sensors, transmit it via transmission technologies, and use data analytics and AI to convert the raw data into information and knowledge based on which market players can make decisions fully automated. Market players, in this context, may be both human actors and software agents that represent human actors. In the latter case, decision-making is fully automated and may either root in the execution of simple rules or more complex AI. With respect to algorithms used for market clearing, advances in optimization approaches and equilibrium algorithms have been particularly relevant in the past and will continue to be at the core of market clearing in the future. Regarding the automated exchange of information, digital platforms, in combination with other information technologies such as data transmission and database technologies, may also play a key role. For instance, market players may use platform technologies to automatically trade electricity and, thereby, match based on supply- and demand-side information. Moreover, market players like network operators and industrial firms may use digital platforms to trade (industrial) demand-side flexibilities, based on automatically collected and submitted production data. Once they trade flexibilities, information technologies may steer production processes automatically, so that they comply with the traded flexibility options. Taken together, the increasing automation of electricity systems calls for adjustments to market design, as a set of new players like, e.g., automated software agents, become active on electricity markets. Moreover, automated trading allows to carry out market interactions at an increasing speed, allowing for shorter bidding intervals or real-time continuous trading. However, this also raises concerns regarding market concentration, as software agents may continuously monitor the behavior of other agents and detect (and punish) deviations of a joint strategy almost instantaneously. As a result, market design has to account for these special properties of automated software agents and adjust accordingly.

In summary, the overall effect of the three technological impacts on the transparency, knowledge, and automation in electricity systems remains, to some extent, ambiguous. From a technological point of view, new information technologies fulfill an enabling and accelerating function concerning the use of decentralized and intermittent RES and, thus, the overarching goal of mitigating climate change. As depicted in Section 3.2, decentralized electricity systems require swift and large-scale data transfers as well as data analyses, which may be successfully addressed by recent developments in information technologies. From an economics point of view, however, new challenges emerge concerning market concentration and abuse of market power. Moreover, new market participants emerge in the form of automated software agents that raise the need for adjustments to the regulatory framework and market design. In particular, market design needs to focus on how to govern and coordinate decentralized electricity systems with a multitude of different players, technologies, and incentive schemes in order to contribute to a successful energy transition also on a global scale.

4 Electricity market design in transition

Electricity markets are dynamic in their nature and have developed from a time with centralized monopolies to carefully designed markets. In particular, the notion of electricity markets usually refers to a multitude of sequential markets, eventually determining the actual dispatch. Aside from these markets, several short-term corrective measures have evolved in order to ensure constant balance of supply and demand. The following sections will point out past developments and current market design concepts and introduce different components of electricity markets in greater detail.

4.1 An international perspective on electricity market liberalization and design

Since the commodity "electricity" comes with a set of unique economic characteristics, the operation of electricity markets is challenging. **Market design** is needed to account for the subsequent peculiarities: First, demand and supply of electricity must be balanced at every point in time and at every node of the network. Furthermore, as indicated in Section 2, the transportation of electricity through transmission lines is constrained by the capacity of the installed lines and their physical properties, which need to be taken into account when scheduling the flow of electricity. Both supply and demand are highly variable over time, which increases difficulties in scheduling the dispatch. Historically, as outlined in Section 3, demand for electricity has been relatively inelastic, so that supply and demand could be balanced primarily by adjusting the supply of electricity. However, with technological progress demand-side flexibility is becoming an increasingly promising solution for dealing with imbalances as well. These factors – which have already been discussed in the previous sections – necessitate the need for a market design enabling the efficient production and distribution of electricity under constrained circumstances. Besides centralized approaches that include, e.g., an omniscient system operator overlooking and optimizing electricity flows through the network, decentralized approaches may further facilitate the coordination of electricity systems. In the latter case, recent information technologies may support the governance of decentralized systems by forwarding relevant information and market signals almost in real-time to the respective market players.

Prior to **market liberalization**, electricity markets were operated by vertically integrated and regulated monopolies, which controlled the generation, transmission, distribution, and retail of electricity by owning generation plants as well as transmission and distribution networks [47]. Due to the technological characteristics of transmission and distribution networks, the minimum efficient size of a firm generating and ultimately supplying electricity to consumers was too large to naturally create competition in these business areas [48]. In the last decades, more and more countries have started to liberalize and unbundle their electricity markets. The business areas of generation, network operation, and retail have been separated to introduce competition in electricity generation and retail. In addition, regulation in transmission and distribution was introduced to ensure an economically efficient electricity supply for consumers [49].

4.1.1 Market liberalization in Europe and the United States

In the **EU**, the liberalization process was started in 1996 and was conducted through two waves of policies regarding the liberalization of the electricity market. Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity has significantly contributed to removing international obstacles and trade barriers [50]. Improved institutional conditions for international trading of electricity has lead to efficiency gains and price reduction. Subsequent and updated directives incorporated the idea of non-discriminatory transmission rights, ensuring a level playing field in power generation. Until today, subsequent steps of EU legislation have followed, leading to the present liberalized electricity markets [51]. However, the degree and design of liberalization differ throughout EU markets. For example, while in **Germany** and **France** access to transmission and distribution networks is assured by regulators, enabling competition among electricity suppliers, the generation side in France is highly dominated by state owned nuclear power plants, which impedes entries of new competitors. In contrast, subsidized RES have penetrated the German market in order to decarbonize the electricity sector by reducing the in-feed of CO_2-emitting fossil fuel power plants. Therefore, even though both countries liberalized their electricity sector with competition on the generation side, outcomes differ significantly on many levels due to political reasons and path dependency.

The **Italian** market constitutes another example. In contrast to most European electricity markets that consist of a single zone, it is split into several internal bidding zones. Electricity supply and demand curves are constructed for individual bidding zones. While the price for electricity received by generators is computed within each zone, prices paid by electricity consumers are based on weighted averages over the whole Italian market. Therefore, scarcity of transmission lines is partly reflected in the power prices for the supply side. These are some examples of differing market designs as well as different market outcomes, which have developed in the EU after liberalization of the electricity sector.

In the **United States (US)**, most electricity customers were served by a vertically integrated monopolist until the 1990s [52]. Regulatory authorities on the state level set prices, allowing the monopolist to cover its cost including a rate of return on capital. This model was transformed in the 1990s by a set of legal developments also known as “electricity restructuring“ [53]. These changes allowed for some form of competition in electricity generation and set the foundation for the liberalization of the electricity market. However, in the US, these reforms were conducted on state level, and not on the federal level due to the subsidiarity principle. Therefore, a set of different models emerged with varying degrees of liberalization until this day [53].

Overall, the processes of liberalization in the US and the EU have led to market designs differing on central design features [47]. This makes the comparison of the US and EU market design especially interesting. In the US, some states have liberalized both retail as well as the generation side. These states have implemented **LMP** systems (also referred to as nodal pricing[1]) and are referred to as “Restructured States” [53]. Regionally responsible Independent System Operators (ISOs) are at the center of these markets, operating both the market and the network system [47]. Therefore, a planned allocation of electricity flows (scheduling) as well as a real-time dispatch of power plants are optimized centrally by the ISO. Prices are computed based on supply and demand within nodes, taking into account the available transmission capacities for electricity trading between nodes. Furthermore, prices are set marginally, which means that the last generating unit sets the price for electricity in the respective node. This pricing system allows for spatially differentiated wholesale electricity prices, where the granularity of the regions considered is determined by the ISO. Nodal pricing was initially introduced by Pennsylvania-New Jersey-Maryland Interconnection (PJM) and is now applied in all ISO markets in the US (Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), California Independent System Operator (CAISO), Independent System Operator New England (ISO-NE), New York Independent System Operator (NYISO), Midcontinent Independent System Operator (MISO), and PJM) [54, 55].

In contrast and as mentioned before, in the EU markets function under the concept of **zonal markets**, where the zones are most often defined by national borders. Under this approach, consumers and producers trade electricity on exchanges and as all bids and offers are received regardless of the location of the market participants, one uniform price for the commodity is established for the entire zone. Contrary to the US model, Transmission System Operators (TSOs) own and operate the network and Nominated Electricity Market Operators (NEMOs) operate the market [56]. Even though multiple NEMOs can be admitted in one bidding zone, their order books have to be merged before market clearing, ensuring single prices. For example, electricity within the German bidding zone can be traded at the exchanges EPEX SPOT, Nord Pool, EXAA and NASDAQ, but as the order books are merged, market outcomes do not differ.

In the EU, the composition and size of the **bidding zones** varies: Germany, Austria, and Luxembourg, for example, constituted a single bidding zone until 2018. However, as of 1 October 2018, this bidding zone was split at the German-Austrian border as a measure to mitigate pressure on the grid. Consequently, power purchases between these countries cannot exceed the capacities of power interconnectors. Other European countries such as Sweden and Norway have multiple zones within their countries, which allow for a certain degree of reflection of the scarcity of transmission capacity. There are also increasing discussions on a fundamental reconfiguration of European bidding zones. The bidding zone review, which was initiated

[1] Technically speaking, nodal pricing refers to the overarching concept of locational price signals, with LMPs as one subcategory. For instance, Section 5 discusses Convex Hull (CH) prices as another form of nodal pricing. Due to its widespread application, nodal pricing and LMPs are often used as synonyms.

on an European level, aims at methodically analyzing the adequacy of bidding zones with regards to numerous output factors. The review summarizes that results highly depend on underlying assumptions as well as the choice of the considered time frame. Therefore, it is a difficult task to suggest new bidding zones, especially with regard to high transaction costs in the case of bidding zone adjustments [57]. Furthermore, it is challenging to define an "optimal" and robust bidding zone configuration which is not already outdated by grid development or changes in the generation/demand landscape once it is implemented [58].

4.1.2 Zonal prices vs. LMPs

There are **inherent trade-offs** between LMPs and zonal pricing models. It is important to consider the degree to which the pricing model affects the ability to cope with the increasing complexities emerging in electricity markets, such as an increasing feed-in of variable and decentralized RES, making it difficult to schedule energy flows, and forecast available network capacities.

In LMP systems the **scarcity of network capacities** is reflected in the LMP, as the ISO determines the intersection between demand and supply of electricity under consideration of network capacities. Therefore, beneficial behavior regarding the utilization of grid capacities is incentivized by the prices [47]. As all relevant network constraints are accounted for, the first best solution in terms of welfare can theoretically be realized when markets clear [59]. In other words, prices reflect the spatial and temporal value of the traded commodity. Since a shortage of generation capacities leads to higher prices in the respective node, LMPs provide a long-term price incentive for the allocation of planned generation plants, if they are stable and robust. This incentive works analogously on the demand side. In theory, LMPs therefore inherently incentivize market participants to efficiently dispatch in the short run and invest in the long run, which reduces the need for expanding grid capacities. This is especially relevant for the current transformation of electricity systems, in particular the spatial allocation of increasingly decentralized renewable energy capacities [60]. However, while there are strong arguments for the superiority of nodal pricing to other forms of market organization based on economic theory, in practice there are additional complexities and issues that need to be taken into account when comparing nodal to zonal pricing. These issues are discussed in more detail in Section 5.

In contrast, uniform pricing schemes do **not reflect physical constraints** of the transmission network in wholesale market prices within a zone. The same is true for zonal pricing schemes if the zonal configuration does not reflect the existing bottlenecks in the grid – by construction, bottlenecks within zones are not reflected by the zonal prices [47]. Thus, market participants do not have a price incentive to consider transmission capacities when offering or demanding electricity. Therefore, congestion of transmission lines needs to be considered by the TSO after markets close. Redispatch and feed-in management measures for renewables are used to manage congestion, as indicated in Section 2. From a theoretical point of view, uniform or zonal pricing cannot guarantee efficient market outcomes if there are grid bottlenecks within zones, as there are no locally differentiated prices that reflect scarcity in transmission capacity. Thus, these uniform prices do not reflect scarcity on the local level.

Moreover, in addition to accurately reflecting grid constraints, prices need to be robust in order to function as an effective signal for long-term investments. Therefore, **robustness of prices** under zonal and nodal pricing is an additional issue which has to be considered when comparing these models [61]. This is particularly crucial in futures markets, which may lack a clear reference price in case of day-ahead prices in LMP systems. As a result, market participants may need to insure against basic price risks involving a risk premium. However, insuring against this type of risk may involve trading de facto financial instruments, which in the EU are covered by Markets in Financial Instruments Derivative II (MiFID II), possibly imposing obligations of financial institutions on electricity market participants. Furthermore, if prices are not aggregated in virtual trading hubs, price determination under LMP systems can suffer from a shortage of liquidity in the local markets, and in particular in futures markets, as the number of market participants typically decreases with higher spatial granularity.

The less liquid markets are, the harder it is for market entrants to compete with existing firms. This issue is closely related to potential problems with market power in nodal systems in situations where transmission capacity is scarce and therefore naturally only a limited number of potential suppliers exist at a given node [62]. As a result, ex-ante market power mitigation measures need to be put in place to detect constellations of few, powerful market participants at individual nodes and to avoid monopoly prices in situations of scarce capacities. Lastly, it is important to note that price signals need to be strong enough in order to efficiently coordinate investment decisions. In practice this is not necessarily the case in nodal pricing, which means that dynamic efficiency can not be guaranteed even with nodal prices, especially in the presence of lumpy investments in generation and transmission. This issue is further elaborated in Section 6. In uniform pricing models or in zonal systems with inner-zonal bottlenecks, wholesale electricity prices generally do not incentivize a spatial allocation of power consumers as well as producers that reflects the impact of the locational choice on the scarcity of transmission capacity.[2]

4.1.3 German market design challenges

There is an ongoing discussion about how to adjust the market design in order to deal with **new challenges** emerging due to the energy transition, e.g., how well large bidding zones are suited to deal with increasing variable feed-in of RES. As the energy transition is associated with large investments into generation and transmission, dynamic efficiency becomes increasingly important. In Germany, frequent market design amendments aim at transitioning the market design step-wise towards setting the right incentives for market participants, as the single wholesale electricity price for the German bidding zone does not incentivize an efficient allocation of investments. A regionally differentiated support scheme for combined heat and power plants incentivizing the installation and operation in the German South (Südbonus) is one of many examples for this adjustment process accounting for newly emerging tasks associated with the energy transition. Additional examples, where the lack in locational incentives via price signals is amended with complex regulatory instruments, are grid reserves, which allow TSOs to contract power plants for redispatch activities in bottleneck situations, or regionally differentiated subsidies for RES.

These examples illustrate the value of a market design that produces the right incentives via efficient price signals, as in the lack of such signals, support schemes, or other regulatory instruments must be carefully designed for numerous technologies as well as regions individually, in order to achieve these incentives. An adjusted market design in Germany that provides improved short-term and long-term price signals to market participants can therefore help to organize the energy transition efficiently. A central aspect in this context is a potential split of the German single price zone into multiple zones or the direct transition to a nodal pricing regime. As there are inherent trade-offs associated with such fundamental regulatory reforms, a careful assessment of advantages and disadvantages of each system is required. To that end, Sections 5 and 6 provide additional academic insights with respect to current market design challenges.

Section 5 discusses how the design of spot markets will have to adjust to the changing economics of market participants due to current changes in electricity systems. The bidding language strongly shapes the possibility to communicate preferences and boundaries, therefore it needs to be tailored to adequately respond to future needs such as flexible demand and supply as well as to allow the efficient coordination between a multitude of different actors with corresponding economic conditions and support schemes. It is crucial for future market designs to address open allocation and pricing problems within spot markets to ensure efficient short-term and long-term investments, especially regarding the changing economics of electricity generation. Moreover today's market design adjustments need to consider future technological developments, anticipating both possible collusive behavior of market participants as well as enabling TSOs to analyze and prevent such behavior, increasingly using AI and machine learning techniques. Section 6 discusses market design implications on long-run investment, market power and strategic bidding. This includes a discussion on different options for support schemes for renewable energies and their implications for market participants.

[2] It is important to note that the concept of uniform prices is used in different contexts and has different meanings accordingly. While it here refers to a single-zone model, imposing an identical locational price over the entire region under consideration (e.g., Germany), it can also describe the more general concept of anonymous, non-discriminatory prices as opposed to pay-as-bid approaches.

4.2 Time sequence of different electricity markets

To discuss the functioning of electricity markets in more detail, this section illustrates the German market structure. Electricity can be traded in different markets that build on each other sequentially. Markets at which only electricity deliveries (MWh) are traded are called Energy-Only-Markets. These mainly include the **futures market** as well as the **day-ahead market**, and the **intraday** markets. In theory, equilibria of supply and demand curves at each traded time slice determine electricity prices [56]. With the increasing generation of weather-dependent RES, the supply curve increasingly depends on variable amounts of wind and solar radiation. Power demand on the other hand is driven by daily as well as weekly and seasonal patterns. Additionally, weather effects can influence the power demand as well. Figure 2 illustrates the sequence of trading activities and markets that the following paragraphs describe [2].

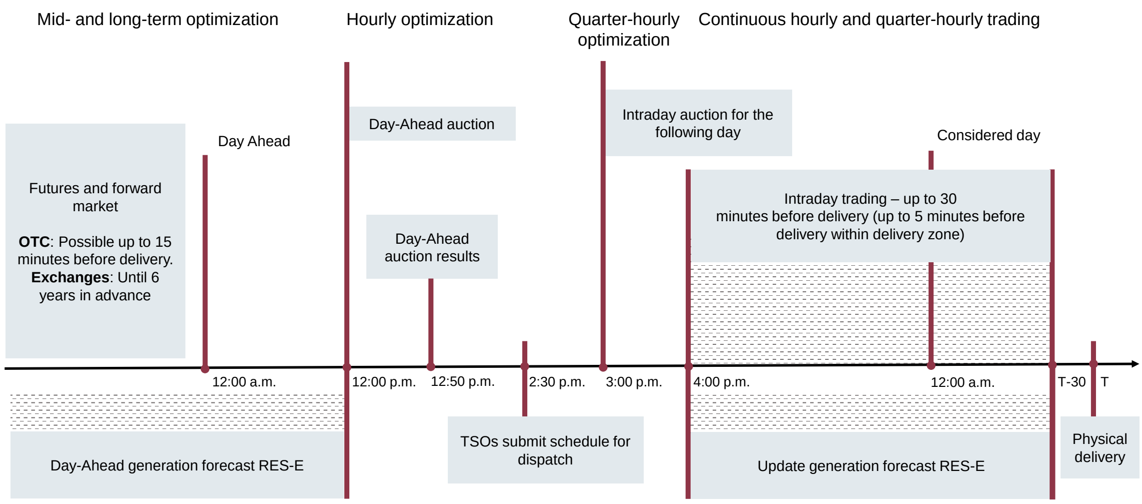


Figure 2: Time sequence of the German Energy-Only-Markets (based on [2])

With respect to the time sequence of power markets, the **futures and forward markets** are the first to mention. They offer market participants the opportunity to optimize their portfolios in the medium to long term and to financially hedge future delivery transactions, either in exchange trading or as over-the-counter transactions. At the exchanges like the European Energy Exchange (EEX), financial futures and options on futures can currently be traded up to six years ahead with plans to extend maturities to ten years ahead.

In the **day-ahead** auction, bids for the following day can be submitted by 12 pm on any day of the year [63]. Various products are traded, including full hours and standardized block bids. The auction results are published at 12.40 pm. When supply matches demand, the market can be cleared, and the market-clearing price is determined based on the intersection of the supply and demand bids sorted by prices. The price of the last accepted bid determines the single market clearing price. The price is limited to the range between −500 EUR/MWh and 3,000 EUR/MWh. The day-ahead market is coupled across bidding zones, thus implicitly allocating interconnector capacity for imports and exports. Price differences between bidding zones therefore balance out, as long as interconnector capacities are not congested. An efficient utilization of interconnector flows therefore contributes to price convergence across market areas. At the same time, making interconnector capacities available to the market implies that transmission capacities within a zone need to be reserved for unscheduled flows (also known as loop flows), thus affecting grid constraints and requiring congestion management.

The **intraday** market distinguishes between the intraday auction and continuous trading on the intraday continuous market [63]. Continuous trading has already been introduced in 2011. The opening auction for 15-minute contracts has been held since December 2014 and takes place all year round at 3 pm on the day before delivery. The auction enables market participants to optimize on a quarter-hourly basis following the hourly optimization on the day-ahead market. As a supplement to continuous intraday trading, the opening auction is designed to concentrate market liquidity and to create a first reference price for the continuous trading period. The auction design is similar to the day-ahead auction, with the price of the intraday auction ranging from −3,000 EUR/MWh to 3,000 EUR/MWh. Following the intraday auction, the results of which will be published at about 3.10 pm, continuous intraday trading for hourly contracts and blocks of combined hours will start at 3 pm, intraday trading for 15-minute contracts will start at 4 pm. This enables the continuous adjustment of trading volumes to intra-hour changes in production and consumption. The closer the trading time is to the time of actual delivery, the higher the accuracy of forecasts, especially with regards to weather forecasts. The adjustment of forecasts affecting the expected generation and consumption can be traded on continous intraday markets as well. Continuous trading is based on a "pay-as-bid" auction format, which means that there are no uniform prices for the products, but rather different prices for the same product depending on the supply and demand at the time of the trade.

Intraday trading is particularly relevant with respect to the increasing feed-in of RES to be able to react to corrected weather forecasts throughout the day. This is also reflected in the development of lead times[3] since the introduction of continuous intraday trading in 2011. In July 2015 the lead time was reduced from 45 to 30 minutes before delivery. In June 2017, it became possible to trade within the area of one TSO up to 5 minutes before delivery. The 15-minute contracts of the intraday market also enable the assessment of flexibility within an hour. Together with day-ahead and intraday hourly trading, which in turn enable the assessment of flexibility between hours, intraday 15-minute contracts represent a market mechanism for managing flexibility. Advances in computational power and optimization algorithms may allow for even finer time granularity that may even get close to real-time – an issue that will gain increasing relevance in the near future. Hence, price signals may reflect flexibility almost immediately and thereby incentivize efficient short-term flexibility offers and long-term investments in flexible production technologies.

It is worthwhile to briefly compare the German time sequence to that of a liberalized electricity market in the US. Here, **PJM** is a suitable example. It is located in the North West of the US and serves 65 million customers with 180 GW of installed generation capacity. The timely sequence of markets is comparable to the German system. The PJM ISO publishes load forecasts before day-ahead trading. Then, market participants can submit bids for the day-ahead market until 12 pm (the delivery day is the next day). Afterwards, the ISO computes hourly LMPs for every node and publishes these prices until 4 pm. Based on these results, market participants can trade once again until 6 pm and adjust their bids and offers. Then, the real-time market opens on the delivery day. The real-time market features a bid-based, security-constrained economic dispatch and is conducted every five minutes throughout the day [47]. Compared to the German design, this market represents a combination of the continuous market and the balancing market, as imbalances are settled on the PJM real-time markets as well. This is a major difference to many European market designs, where separate imbalance settlement systems are in place, operated by the TSOs. Lastly, after real-time markets close, the PJM ISO settles physical imbalances which is part of the ancillary services.

4.3 Short-term, corrective measures

4.3.1 Markets for balancing capacity and balancing energy

In electricity networks it is crucial to **maintain the frequency** at a constant level, for example 50 Hz in the European Network of Transmission System Operators for Electricity (ENTSO-E). Therefore, supply and demand have to be balanced at every point in time and at every node of the network. In Germany, the TSOs are legally obliged to guarantee system stability by providing system services. These measures can be network-based actions such as operating power switches or market-based actions such as the balancing market for reserves, which are activated only after energy markets close. Balancing energy is the short-term adjustment of supply and demand at the time of physical dispatch, i.e., after market closure. It is

[3] Lead time is the time between the last possibility to trade and the beginning of the actual delivery.

only used in the event of a system imbalance and not in the event of grid congestion. This system service aims at maintaining network stability, more precisely to maintain the target frequency of 50 Hz. Balancing energy is distinguished into positive and negative actions. Positive balancing energy is used when there is a shortage of supply. Negative balancing energy is retrieved when the frequency is too high and there is a shortage of power demand.

The TSOs tender volumes for three types of balancing energy at the **balancing capacity markets**. The Frequency Containment Reserves (FCR) (German: Primärregelleistung) provides instant frequency recovery. It is automatically activated when measurements at the unit indicate frequency deviations and has to be available within 30 seconds. FCR is tendered as a symmetrical product, as participating units have to provide both positive and negative balancing energy. The TSO acquires capacities according to the merit order of capacity prices only. No further remuneration is paid for the provision of energy in the case of an activation of the service. The Automatic Frequency Restoration Reserve (aFRR) (German: Sekundärregelleistung) as well as the Manual Frequency Restoration Reserve (mFRR) (German: Minutenregelleistung) are similar products with differing technical requirements regarding the activation time. aFRR needs to be available within 5 minutes and mFRR has to provide balancing energy within 15 minutes. aFRR is activated automatically, whereas mFRR is controlled remotely by the TSO. Capacities for both aFRR and mFRR are activated based on a merit order of capacity prices as well. However, the retrieval of energy is activated according to the merit order of bids submitted at a second energy market, where formerly only those participants could offer energy that have been successful at the capacity market. Since the amended regulation, which is fully in place since 3 November 2020, a separate balancing energy market in distinction to the balancing capacity market is introduced, called Regelarbeitsmarkt (balancing power market). Thereby, providers can offer balancing energy up to one hour before the considered time period, regardless of whether they have offered capacities on the balancing capacity market. Balancing energy is then activated based on the updated merit order considering all bids. Remuneration for aFRR and mFRR therefore differs from FCR remuneration. Participants at the balancing markets need to be prequalified to ensure the fulfillment of all technical requirements to deliver balancing power.

In the US reserve capacities are tendered by ISOs as well; however, they function differently in comparison to the German market design. There is a stronger focus on technical properties of the generation plant providing balancing power capacities compared to the focus on delivery time in the German model. In contrast to Germany, system imbalances in power demand and supply – for example due to generation and load forecast errors – are not compensated by the balancing power market but by the real-time markets. The ISO operates the real-time market, where electricity trade occurs in the form of five-minute products up to five minutes before physical delivery to ensure system balance.

4.3.2 Redispatch and feed-in management

In contrast to system imbalances, **network congestion** is mainly addressed by redispatch and feed-in management. Redispatch refers to the intervention ordered by the TSOs in the originally dispatched flow of conventionally generated electricity to shift the feed-in to either prevent (preventive redispatch) or remedy (curative redispatch) grid congestion. The prediction of congestion occurs mainly after the day-ahead auction. Based on this prediction it is necessary to reduce the power feed-in of conventional power plants with more than 10 MW installed capacity before the congested transmission lines (negative redispatch) and to increase it behind the bottleneck (positive redispatch). Therefore, redispatch measures are balancing-neutral in terms of total quantities.

As mentioned in Section 2, the two main redispatch approaches involve cost-based and market-based redispatch. Under a system of cost-based redispatch, as currently employed in Germany, all generators with more than 10 MW installed capacity are qualified to be subject to redispatching. In case they are indeed instructed to change their output, the generators will be reimbursed for the incurred costs. In contrast, a market-based redispatch allows generators to voluntarily submit bids that express the desired reimbursement. The determination of redispatch occurs in a least-cost fashion and the compensation for affected generators is according to their bids [64].

In case of remaining congested transmission lines, Distribution System Operators (DSOs) can use feed-in management almost as a matter of last resort to reduce the in-feed of electricity generated by RES as well as combined heat and power generators. This action comes as one of the last to manage congestion, as renewable energies feed into the grid with priority, to support the transition from fossil fuels to renewable energies. Therefore, feed-in management only applies when it is imperative due to system security. Increasing installed capacities of renewable energy without expanding grid capacities will likely increase the incidents and volumes of feed-in management as well as redispatch measures. Further, Germany has made an amendment to the laws regarding congestion management introducing Redispatch 2.0. From 1 October 2021 onwards, TSOs will be allowed to also redispatch renewable power plants in order to prevent or remedy grid congestion, as long as the power plant exceeds 100 kW installed capacity (the new size requirement also holds for conventional power plants). The new law does not change the fact that redispatch for conventional power plants occurs first, as the feed-in priority of RES still holds in principle. In both cases operators have to be compensated for reducing or increasing power generation, which increases power prices for consumers.

5 Market design options: allocation and pricing rules

This section focuses on allocation and pricing on electricity spot markets, mainly on day-ahead markets, given their importance in Europe. We briefly touch on intraday, real-time, and balancing markets, but an in-depth discussion is beyond the scope of this section. Current and novel concepts for the bidding language are introduced and combined with a discussion on existing pricing schemes and their limitations.

5.1 Bidding languages

Different bidding languages are used on different markets, directly impacting the allocation problems that need to be solved, and the pricing rules employed.

5.1.1 Day-ahead markets

Day-ahead markets are centralized auction markets. Market participants place their bids using the auction's bidding language. This bidding language consists of a set of parameters that allows the participants to communicate their valuations or cost structures. The market operator then solves the allocation problem based on these parameters to determine a day-ahead schedule of generation and consumption and calculates prices [56]. Day-ahead markets are complemented by intraday or real-time markets. These markets modify the day-ahead schedule to determine the actual physical dispatch, as described in Section 4. Especially in European countries, the day-ahead market is considered to be the main reference market, while in the US it mostly possesses the notion of a forward market for the real-time market that determines the dispatch [44]. In day-ahead markets in the EU, participants usually submit bids for every hour of the next delivery day. Based on the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA), clearing and pricing are combined in a single computationally complex optimization problem. In essence, assuming bids reflect true costs and valuations, the algorithm intends to find a welfare-optimal allocation requiring a uniform price within each price zone (such as Germany) as well as feasible cross-zonal power flows according to flow-based market coupling principles in day-ahead auctions [65]. Transmission network parameters within a zone are not taken into account, as no intra-zonal congestion is assumed at this point.

Bids in day-ahead electricity markets are submitted in a predefined bidding language. Bidding languages should allow for the expression of the underlying opportunity costs and economics in order to enable efficient outcomes [66]. For instance, suppliers typically incur certain fixed costs for starting up and running a generator, as well as variable electricity production costs. Moreover, the operation is often subject to technical conditions, e.g., referring to minimum runtimes or ramping constraints. On the demand side, market participants might want to express certain flexibility dimensions. The economics of electricity storage technologies might depend on the transitions between supply and consumption of electricity.

In the EU, aside from regular bids for individual hours of the day, the bidding language allows for **block bids**. Representing a set of individual bids that can be executed only as a whole [65], they aim at permitting market participants on the supply side to express operating conditions. Cost structures are communicated as single-part offers, requiring market participants to aggregate various cost components into a single parameter. It is explicitly refrained from the communication of multiple cost components in order to promote decentralized decision-making on the part of the market participants [56]. Therefore, the bidding language permits a less detailed expression of economics than, for instance, bidding languages used in the US. Orders can be submitted with or without a price limit. Currently, EUPHEMIA is capable to accommodate certain types of flexibility such as:

> *Flexible hourly blocks*, in which under a fixed price limit, a fixed volume can be either fully accepted or rejected. In case of being accepted, it is the algorithm (and not the participant) that defines at which hour that volume would be supplied. This type of flexibility option would be similar to what we will call *shiftable volumes* (see Fig. 4 **c)**).

> *Load gradients* are defined on a set of hourly orders where the load on consecutive hours is bounded in terms of the previous one. This type of flexibility option relates to the more general *adjustable load* (see Fig. 4 **e)**).

> *Minimum acceptance ratios*, which can be specified for block orders. Blocks are either fully rejected or cleared with a quantity above the minimum acceptance ratio. Blocks may thus be curtailed until the minimum acceptance ratio, again referring to *adjustable loads* (see Fig. 4 **e)**).

However, features in EUPHEMIA are not necessarily available in all NEMOs in the EU. From the above list, the European Power Exchange (EPEX) as a relevant NEMO for Germany so far only provides minimum acceptance ratios. Operador do Mercado Ibérico de Energia (OMIE) has established minimum income conditions for the Spanish market, where participants can specify a lower income threshold consisting of a fixed and a variable component reminiscent of multi-part bids in the US. In Italy's multi-zonal system, certain demand orders are not settled at the respective zonal price but at some national uniform price [65].

US ISO markets also aim to find a welfare-maximizing dispatch based on bids but separate the market clearing from the subsequent price determination. In nodal markets bids and offers, resource constraints, network constraints, transmission losses, and certain ancillary service requirements are co-optimized. As a result, the electricity price is the marginal cost of supplying electricity at a specific node in the network. The nodal model includes as basic features a centralized real-time bid-based security constrained economic dispatch (SCED) and a real-time price settlement where imbalances are settled against LMPs.

The nodal system aims at considering important physical grid characteristics in the optimization. Of course, the allocation may be distorted if bids do not represent the market participants' preferences or if the technical costs and constraints are inadequately formalized [67].

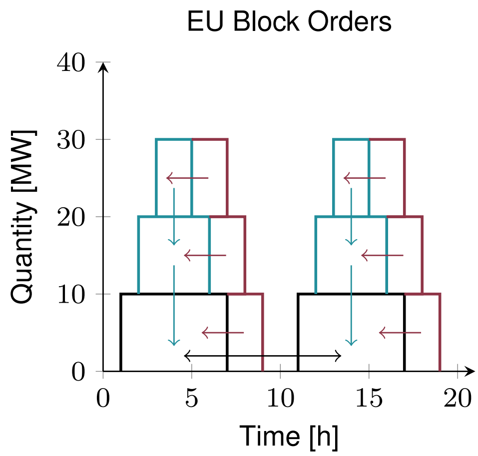
Market participants in the US are generally permitted to indicate their opportunity costs in a more granular way than in the EU [68]. Cost structures can be communicated with **multi-part bids**, usually consisting of start-up costs, no-load costs as well as an offer curve. Furthermore, generators can express technical constraints such as minimum up and down times, minimum and maximum output levels, ramp rates, or start-up times [56]. So called self-schedules are pure quantity bids specifying an amount of energy that needs to be dispatched regardless of price levels or cost structures. Demand-side bids comprise price-inelastic self-scheduling as well as price-elastic bid curves [47]. Moreover, the Federal Energy Regulatory Commission (FERC) has defined a minimum set of bidding parameters for storage resources, including charging and discharging quantity limits, time limits, or ramp rates as well as specifications of minimum, maximum, initial, and final states of charge [56].

Single-part and block bids have been found to handle uncertainties on electricity markets in an inefficient manner [69, 70], in particular compared to multi-part bidding languages in the US [71]. A future EU day-ahead market design would benefit from multi-part bidding of cost structures and enable an expression of inter-temporal constraints, such as start-up, shut-down, and ramping restrictions. These will also play an important role with a higher penetration of renewable energies, because conventional generators are required at times to balance the market. Block bids in current EU markets allow for little flexibility and participants often have to submit an unreasonable amount of bids to appropriately express characteristics of their generators.

5.1.2 Bidding languages example

Figure 3 compares the block bids available on the EPEX and US bidding languages for an exemplary supplier. The economics of this supplier can be directly expressed in the US bidding language. In this example, the generator is subject to minimum (10 MW) and maximum (30 MW) periodic outputs, limited ramp-up and ramp-down capacities (10 MW/h), as well as a minimum up (6 h) and down (10 h) time once the generator has been started up and shut down, respectively. As long as these constraints are satisfied, the electricity can be dispatched at any point in time during the day.

In order to express these few parameters with block bids, many such bids have to be submitted. The blocks marked black in Figure 3 represent the minimum output that has to be dispatched over the minimum runtime. In addition, the blocks marked green are defined to express the ramping constraints and the maximum output. However, these blocks must be bid as so-called linked block orders, as they can only be dispatched if the base block marked black is also cleared [56]. This is represented by the green arrows, specifying the dependence of the green children blocks on the black parent block. Since the generator can run longer than the minimum up time, additional linked block orders marked red have to be submitted to optionally extend the runtime. This bundle of block orders may now be submitted for different points in time, yet due to the minimum down time, only one of those bundles can be dispatched. The base blocks of the bundles therefore have to be submitted as exclusive block orders [56], as represented by the black arrow.



US Bidding Language

Minimum output: 10 MW

Maximum output: 30 MW

Ramp rate: 10 MW/h

Minimum up time: 6 h

Minimum down time: 10 h

Figure 3: Supply bidding language comparison

Increasing uncertainties in decarbonized electricity markets increase the need to adequately express supplier economics and, as the example illustrates, leads to an increasing number of block bids and computational complexity [56]. A direct expression similar to US bidding languages might therefore be more expedient.

5.1.3 Demand-side flexibility

In addition to the generation side, the market design should also address relevant aspects of the demand side [47]. Tradeable products should allow for a better expression of flexibility, yet retain reasonable communication and computational complexity. Flexibility extensions of the bidding language could include shiftable volumes (asking to meet a certain volume within a certain time frame), shiftable profiles (allowing to shift a pre-determined load profile over time), or adjustable loads (involving extensible or reducible loads) [72, 73, 74]. Besides, block-orders seem to inhibit the efficient operation of storage resources [75]. This suggests upsides through more explicit bidding formats [76].

Exemplary elements of a bidding language for the demand side are illustrated in Figure 4. A price-inelastic consumer submits self-scheduled loads (a) in order to set up the desired fixed profile. Figures (b) to (e) show how the same load might be cleared under alternative demand bid types. For instance, price-elastic loads (b), unlike self-schedules, are not inevitably cleared, but the accepted quantity depends on the market price in every period. If the bid represents a shiftable volume (c), the load may be delivered as an arbitrary profile within the specified time. The charging process for electric vehicles might be an example for a shiftable volume [73]. The individual periodic loads of shiftable profiles (d) may not be altered, yet there is flexibility with respect to the time of delivery, potentially applying to certain industrial processes. Finally, the target profile of adjustable load bids (e) might be curtailed or overconsumed, usually being associated with opportunity costs or values of lost load. Examples could be the interruption of industrial processes or the dimming of light [73].

5.1.4 Intraday and real-time markets

In order to allow market participants to immediately resolve forecasting errors with respect to their operating plans, intraday markets in the EU allow continuous trading almost until delivery. In particular, trade orders

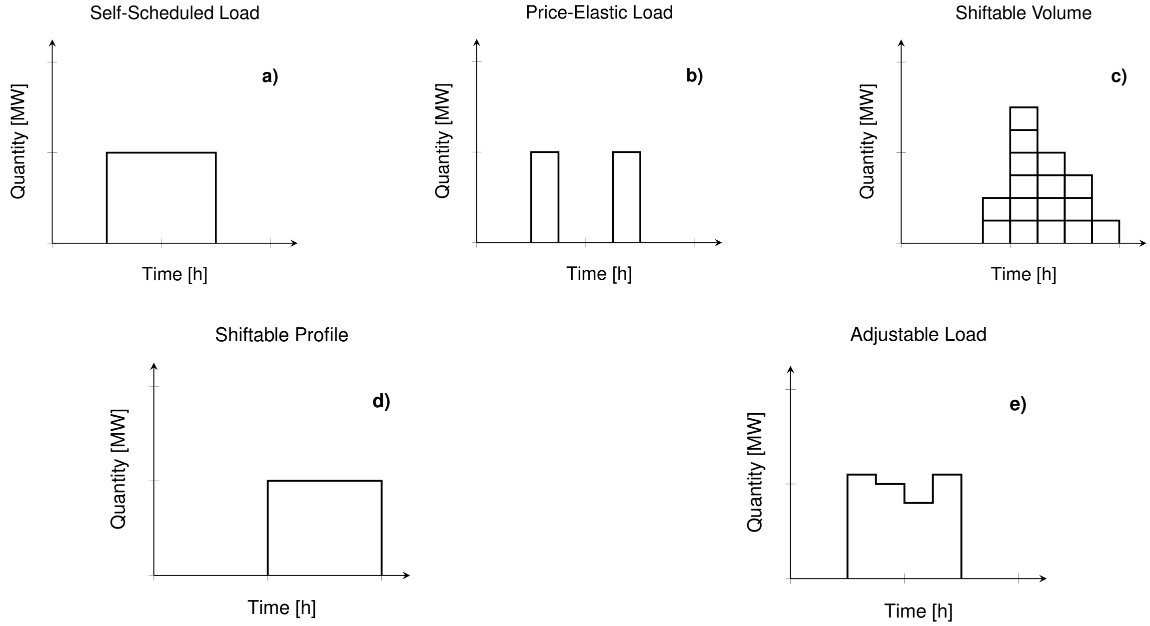


Figure 4: Exemplary demand bidding language

can be placed at any time and are executed at once. As mentioned in Section 4, the intraday market can be accompanied by an initial auction to concentrate liquidity and to establish reference prices. This initial auction follows similar rules as the day-ahead auction, featuring single-part and block bids. These types of bids can also be bilaterally traded in the continuous trading phase following the auction. The final dispatch is subject to single-sided remedial actions by TSOs in order to allow a compatibility with grid restrictions, as described in Section 4. As part of the Cross-Border Intraday (XBID) (now Single Intraday Coupling (SIDC)) project, a joint pan-European intraday market has been developed, supporting continuous cross-border trading and aiming at increased efficiency [44]. Based on a shared order book and a flow-based market coupling to compute cross-zonal flow capacities [44] in day-ahead markets, bids are matched with bids from either the same zone or with bids from other zones where sufficient cross-zonal capacity is available [77].

US market designs combine the day-ahead market with a real-time market as part of a so-called two-settlement system. While intraday markets in the EU are typically regarded as corrective entities, the real-time markets represent the main reference point in the US [44]. Bidding languages and allocation rules for the underlying bid-based security-constrained economic dispatch follow the principles of the day-ahead market and deviations to the day-ahead schedule are settled at the respective real-time price [56]. The outcome of the real-time market is the final dispatch, since all grid constraints are inherently taken into account by the nodal system.

In EU intraday markets, the matching of buy and sell orders could be the subject of future refinements. Shifting from bilateral to multilateral matchings would lead the way to trading more customizable profiles, such as flexible loads [78]. In terms of the bidding language for EU intraday auctions, similar arguments in favor of more extended bidding formats, in particular for flexible demand and storage, can be made as for the day-ahead market.

5.2 Pricing rules

Section 4 outlines that the zonal pricing in the EU and the LMP in the US are a central difference in the electricity market design of both jurisdictions. This section first elaborates on these differences and the up- and downsides of LMPs in contrast to zonal pricing. This is followed by a discussion on specific pricing schemes, i.e., mechanisms to compute the uniform prices on a single node in the presence of non-convexities in the cost structures of generators. US ISOs have adopted different schemes with specific properties over time that are important in this context.

5.2.1 Nodal vs. zonal pricing

It is well-known that uniform and anonymous competitive equilibrium prices do not necessarily exist in markets with non-convexities [79]. Due to the requirement of uniform prices within large price zones, the outcome of the current zonal system in the EU deviates from the welfare-maximizing outcome [80]. A stylized example is provided in Section 5.2.2. Moreover, intra-zonal grid constraints are not considered during the trading. As a result, the computed allocation could be infeasible, leading to a redispatch by the TSOs and corresponding welfare losses, as discussed in Section 4. A number of theoretical arguments are clearly in favor of LMPs:

1. Welfare gains
2. Better regional investment signals in the form of local prices
3. Lower levels of redispatch and feed-in management due to the consideration of network constraints during the trading
4. No need for (non-trivial) definitions of appropriate and stable price zones

These advantages have to be weighed against some potential problems that could arise during the implementation of LMP systems. The following list provides a brief analysis of the four points above, as discussed in the literature.

1. First, evidence from nodal markets in the US shows that enhanced operational incentives in California led to a **more efficient system operation** of gas power plants of around 2.1 % (as well as lower fuel consumption by 2.5 %) [81], while consumer prices decreased by approximately 2 % in Texas [82]. A similar order of magnitude is expected for Europe [83]. A recent report by the European Commission highlights short-term and long-term efficiency gains [44].
2. A nodal pricing system sends better **local price signals** [47, 84], contributing to regional investment incentives for generators [85, 86]. In the long run, if participants respond to these investment incentives, there will be sufficient generation and transmission capacities such that nodal electricity prices are similar across Germany. In fact, in the US price differences across nodes tend to be minor, except in times when transmission constraints become binding [47]. However, some words of caution are in order. Although locational marginal pricing improves investment incentives, locational investment decisions are driven by a variety of factors such as site availability, access to transmission and distribution grids, or resource availability. In addition, lumpy investment in transmission and generation make long-term financing based on expected nodal prices inherently difficult. For example, empirical evidence for Texas suggests that nodal prices may not be the primary driver for the allocation of investments [87]. This particularly applies to investments into RES, which are currently largely driven by subsidy schemes, limiting the exposure to wholesale market signals for investors [88].
3. Incorporating grid restrictions into the allocation and pricing problems **reduces the need for redispatch and feed-in management**. Costs for redispatch and feed-in management have increased substantially in Germany over the years and are socialized to the general public. As outlined in Section 2, both a cost-based redispatch (due to unknown opportunity costs) and a market-based redispatch (due to gaming) in large price zones are subject to downsides [89]. The consideration of transmission constraints in LMP leads to much lower levels of redispatch [44], alleviating the associated drawbacks.
4. Some of the advantages of nodal prices come from challenges of a zonal pricing system. **Zonal configurations are inherently instable** [90], as congested lines shift with weather patterns and future changes in the capacity mix [83]. This implies a need for frequent re-zoning, yet this would undermine long-term markets and investment incentives [88]. In addition, zone splitting is very challenging and may even lead to welfare losses [91]. This is also an important argument to move to LMPs in one step

rather than to partition the country into smaller and smaller price zones. As most congestion occurs within zones, there is an inherent trade-off between intra-zonal congestion (solved by redispatch), and capacities made available for cross-border trading. This trade-off has been regulatory addressed by the definition of minimum trading capacities, so-called minRAM rates. Utilization levels of the electricity grid have to be reduced to reserve a minimum of the elements' capacities for cross-zonal trading. This trade-off is inherent to to zonal markets, and necessarily sub-optimal if set in a static way, and can lead to welfare losses [92]. This can be avoided in the nodal market design, as the congestion is inherently considered. Furthermore, there is evidence from a case study for Germany, Poland, the Czech Republic, and Slovakia that even when coupled to other zonal markets, nodal pricing outperforms zonal pricing [93].

A recent report by the European Commission [44] provides an up-to-date summary of the benefits and challenges of introducing nodal pricing. For example, they mention the changing role of the day-ahead market, and the required institutional changes as challenges. In particular, the role of TSOs and NEMOs will have to be revisited. Apart from the points raised in the Staff Working Document, a host of administrative and policy issues will need to be addressed. For example, to realize the full synergies from effective renewable support mechanisms and nodal pricing, reforms of both mechanisms need to be coordinated. A transition to nodal pricing would require a structural reform of current support schemes for RES. Another difficulty might arise from the current organization of retail markets. Given the increased complexity and volatility in wholesale prices, a transition to nodal pricing could impede competition in retail markets for electricity. Next, the current structure of electricity prices for end consumers on the demand side suggests that incentive structures are distorted by additional price components such as grid fees, taxes, or levies. Hence, even a nodal pricing setting might not lead to efficient short-term price signals if these distortions are not addressed by complementary reforms [88].

In this single subsection, it is impossible to discuss all potential problems that might arise from a transition to a nodal system. However, some frequently raised concerns, as also indicated in Section 4, refer to the following potential challenges:

1. Low liquidity and risks of market manipulation at nodes
2. Hedging and basis risk
3. Costs of the transition
4. EU perspective
5. Distribution grid

The following paragraphs elaborate further on these challenges and possible solutions.

1. **Low liquidity and risks of market manipulation at nodes:** Market power is often mentioned as a concern in nodal pricing systems. Other jurisdictions such as the electricity markets in the US have found effective ways to mitigate these risks [47]. As this topic is more evolved, Section 6 provides an in-depth discussion on this matter.

2. **Hedging and basis risk:** Price differences between nodes in the electricity markets are small in the US and particularly arise if the transmission network is congested. In the long-run, locational investment signals due to nodal prices should reduce these differences. Of course, efficient hedging via futures and forward markets is important in this context and will be discussed below. In a nodal system, participants have to hedge at local trading hubs which do not exist for every node. When prices differ across nodes, finding a suitable hedge becomes challenging. All US electricity markets auction Financial Transmission Rights (FTRs), which provide the congestion rent from a source to a sink node. FTRs allow the holder to be paid the difference in price between two coupled markets [94] and thereby reduce the need for unreasonably many trading products. It appears that in the US, trading at and between the hubs is very liquid in the forward exchanges [44].

   In addition to FTRs, most US nodal pricing regimes have introduced Auction Revenue Rights (ARRs) in an effort to promote liquidity and financial arbitrage opportunities across the transmission system.

ARRs have been introduced in addition to FTRs to encourage participation in the FTR auctions and to increase liquidity. While FTRs are typically short-term (months to a few years), ARRs are typically issued for 10-year periods and allow for long-term hedging of congestion costs in the transition to nodal pricing [94]. ARRs also offer an opportunity to enhance the liquidity of markets for FTRs between individual nodes and nearby hubs. Dependent on generation and demand type, market participants may also choose to not hedge some of the corresponding, typically small price difference (often referred to as basis risk).

Importantly, futures and forward markets in the US are organized around hubs. The nodes of a trading hub are used to calculate a reference price that can be employed by the market participants for different types of hedging. The need for such a reference price is due to considerable variability of energy prices at different nodes and periods of time. Trading at and between these hubs is very liquid in the futures exchanges (e.g., the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE)) [94]. In Germany, one could initially imagine reference prices for a North hub and a South hub. They can be calculated indefinitely and hence can serve as basis for hedging contracts. They can also easily be complemented by further reference prices to be calculated by market operators, whenever the congestion patterns make these attractive and market participants request it.

Lastly, a basis risk, even if very low, means that financial hedging in futures markets is no longer a perfect hedge. This is the case when there is a mismatch of physical (spot) prices and prices of financial (derivative) trading products, i.e., when the underlying of the traded derivative such as a virtual hub price or a system average price is different from the actual (locational) spot price exposure. European and national financial regulation could thus have an implication on market participants [95]. Derivatives that cannot be fulfilled physically could be deemed financial instruments rather than hedges under the MiFID II regulation which would imply that their trading is classified as speculative investments. This would, in particular for municipal-owned utilities, be difficult to comply with. Therefore, an early clarification and potential adjustment of regulation for commodity markets could be necessary to enable all market participants to continued long-term exposure minimization using derivative trading.

3. **Costs of the transition:** The costs of a transition from a zonal to a nodal system might be high. However, Neuhoff and Boyd [94] show that the US ISOs that have undertaken the transition to a nodal pricing regime have recovered the implementation costs (one-time costs) within one year of operation. The authors argue that additional benefits include better congestion management, improved grid reliability, increased retail access and competition, reduced transaction costs, improved planning, and better coordination with regulatory agencies.

   It is important to note, however, that the experiences in the US were made under inherently different institutional settings. The transition process implied by the German and European climate targets naturally emphasizes the importance of dynamic efficiency, due to substantial and simultaneous needs for investment into new generation technologies as well as transmission and distribution grids. Hence, as outlined in Section 4, it remains unclear whether the anticipated dynamic benefits from a nodal pricing system – in addition to the undisputed static benefits – can be fully realized in the highly dynamic settings expected in the coming years in Europe and Germany.

4. **EU perspective:** Embedding a nodal system in, e.g., Germany into a coupled European electricity market consisting of zonal systems would constitute another institutional and practical challenge. For instance, coupling the electricity markets of European countries with different pricing systems may be highly complex and thus difficult to implement. Overall, the integration of a nodal system in, e.g., Germany would have to encompass the day-ahead, intraday, and balancing markets. A possible way to manage such an integration may be to use auctions over these time frames [89]. Also, the current computation of day-ahead prices in Europe using EUPHEMIA will require significant changes.

   Given the history of discussions in Europe, market-based congestion management would most likely be seen favorable by the EU Commission and other member states. Two specific proposals could already lead to efficiency improvements:

First, a transition from physical to financial balancing group responsibility would allow trading in the spot market for each plant instead of for entire portfolios. This increases the transparency of the expected power flows and thus improves the starting position for redispatch.

Secondly, this could lead to a change from the usual block bids, which are very complex to cater for portfolios, to multi-part bids for plants with a structure that is easier to use also for smaller market participants and market platforms. This might also address current challenges regarding the Market Clearing algorithm EUPHEMIA. Substituting several block products with multi-part bids would allow clearing to take place faster and lead to a more efficient solution [96].

Building on these improvements, the European framework would then also be better prepared for the transition (initially) of individual member states to nodal pricing. It would still have to be clarified whether in a longer-term perspective the entire EU electricity market would be cleared by a central algorithm, or whether recent experiences from the US could be leveraged, where several regions with parallel clearing algorithms are linked via effective interfaces (e.g., [97]).

5. **Distribution grid:** With the growth in distributed generation and flexibility provision, the importance of effective congestion management in the distribution grid is also growing for both nodal and zonal pricing in the transmission grid. However, as renewable production and resulting congestion on distribution and transmission grids are regionally correlated, even nodal pricing applied only on the transmission grid level can be expected to support regional balancing of supply and demand, thereby also reducing or avoiding congestion in the distribution grid. Furthermore, there is already positive experience, for example from California [98], on how structural congestion in the distribution grid can also be taken into account in the nodal clearing algorithm.

   It has been shown that a consistent market framework at the transmission grid level provides a clear and well usable interface for solution approaches in the distribution grid. This clear and long-term robust interface between transmission and distribution grid seems to be especially important for the development of the framework for an effective congestion management on the distribution grid level [99], and the incentives this creates for the development of decentralized technologies, business models, and infrastructure.

5.2.2 Pricing schemes for non-convex cost structures

Irrespective of the discussion on zonal and nodal prices, pricing rules need to address non-convexities in the cost structures of these markets. Those can be described as costs that abruptly grow under certain conditions. Typical examples are start-up costs (fixed cost triggered by starting up the generator), or minimum supply requirements (that induce discontinuities into the objective functions). The following example taken from Madani et al. [68] depicts a case where no uniform price supports a **competitive equilibrium**, because of the presence of non-convexities. A competitive equilibrium in this context refers to the situation in which no player has an incentive to deviate from the suggested solution (allocation and pricing). The result that in the presence of non-convexities there may be no uniform price supporting a competitive equilibrium is rather general (e.g., [79]), and it is one of the main reasons why different pricing approaches have been suggested in the literature (e.g., [100, 101]).

Table 3 shows a case with two generators, G1 and G2, and two buy-side bidders, D1 and D2, each of them having a **limit price**. For generators the limit price is the minimum amount they are willing to accept per unit of produced energy, for consumers the limit price is the maximum amount they are willing to pay per unit. The **quantity** represents the maximum capacity in the case of generators and the total demand in the case of consumers. Finally, generator G1 has a constraint on the minimum production, where they need to produce at least 11 MW (this introduces the non-convexity).

Figure 5 depicts the allocation and pricing rules for the setting described in Table 3. A brief analysis of each case can be found below. We refer to two different pricing schemes that will properly be defined by the end of this section. These are **Integer Programming (IP)** and **Convex Hull (CH)** pricing schemes.

> Fig. 5 **a)** shows allocation and pricing determined by the intersection of the supply and demand

KOPERNIKUS PROJEKTE
SynErgie
Die Zukunft unserer Energie

GEFÖRDERT VOM
Bundesministerium für Bildung und Forschung

Table 3: Example of allocation and pricing under non-convex costs.

Type	Unit	Generation		Demand	
		G1	G2	D1	D2
Limit Price	EUR/MW	40	100	300	10
Quantity	MW	12	13	10	14
Minimum Production	MW	11	-	-	-

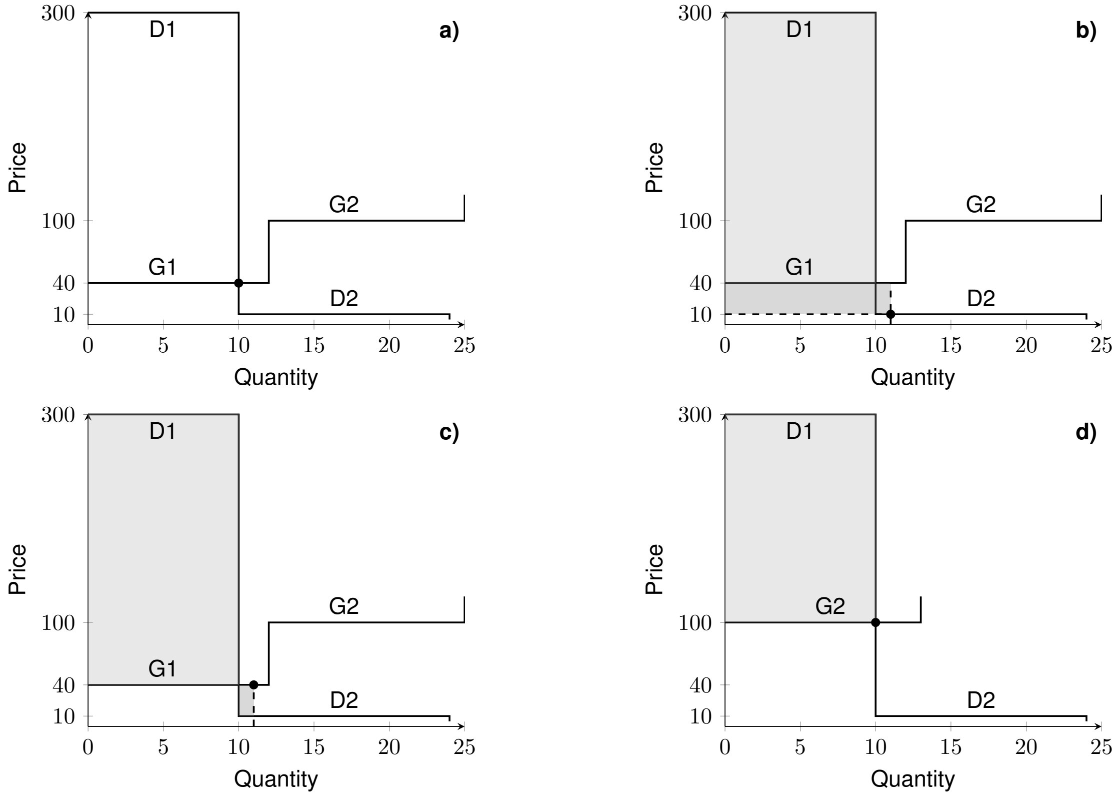


Figure 5: Stylized examples for allocation and pricing: **a)** shows the (infeasible) allocation of 10 MW (10 to D1, 10 from G1; reject D2,G2) at a price of 40 EUR/MW; **b)** shows the allocation of 11 MW (10 to D1, 11 from G1, 1 to D2; reject G2) at a price of 10 EUR/MW; **c)** shows the allocation of 11 MW (10 to D1, 11 from G1, 1 to D2; reject G2) at a price of 40 EUR/MW; **d)** shows the allocation of 10 MW (10 to D1, 10 from G2; reject D2,G1) at a price of 100 EUR/MW, as applied in European markets.

curves, which gives an infeasible solution: allocate 10 MW from G1 to D1 and reject D2 and G2, with a price of 40 EUR/MW. This solution is infeasible, because G1 has a minimum production of 11 MW.

> Fig. 5 **b)** shows the solution that would be suggested under the **IP pricing**[4] scheme, broadly used by most ISOs in the USA: allocate 11 MW from G1, 10 MW to D1, 1 MW to D2, and reject G2, with a price of 10 EUR/MW (such that D2 is willing to participate). In this case G1 makes a loss, and will need to be compensated (with 330 EUR) to be willing to participate.
Welfare: (300 EUR/MW$-$10 EUR/MW)$\times$10 MW$-$330 EUR$=$2,570 EUR.

> Fig. 5 **c)** shows the solution that would be suggested under the **CH pricing** scheme, broadly used by

[4]See the description of IP (Integer Programming) and CH (Convex Hull) pricing below

MISO in the US: allocate 11 MW from G1, 10 MW to D1, 1 MW to D2, and reject G2, with a price of 40 EUR/MW (such that G1 is willing to participate). In this case D2 makes a loss, and will need to be compensated (with 30 EUR) to be willing to participate.
Welfare: (300 EUR/MW−40 EUR/MW)×10 MW−30 EUR=2,570 EUR.
Importantly, cases **a), b), and c)** imply that no uniform price is able to support a competitive equilibrium, and some compensations (uplifts) are necessary as an incentive to accept the proposed allocation and price.

> Fig. 5 **d)** shows the solution that would be suggested under the EU rules (if the minimum requirement was internalized into the bid): since including G1 will necessarily lead to external compensation, this generator is (paradoxically) rejected and the solution is obtained using the remaining bids. This implies to allocate 10 MW from G2 to D1 and to reject D2, with a price of 100 EUR/MW. Such a solution leads to a lower welfare: (300 EUR/MW−100 EUR/MW)×10 MW=2,000 EUR.

The example illustrates the welfare losses associated with pricing mechanisms in the EU. Moreover, the welfare-optimal allocation can be supported by a variety of prices and side payments. Aiming to achieve certain economic properties (e.g., maximum welfare, budget balance, individual rationality etc.), as well as being computational efficient, many pricing schemes have been proposed over the years, both by the academic literature and practitioners (e.g., PJM).

Figure 6 gives an overview of pricing schemes and is based on a classification made by Liberopoulos & Andrianesis [102]. The authors consider a one-sided market (with few generators and fixed demand). The colors separate the main approaches as classified in the literature. While most of the implementations in real markets are associated to the approaches marked green (including the different cases in Figure 5), there is still continuous research around the other two categories. The green rectangles represent pricing schemes that set up a uniform price plus some compensations for the sellers called **uplifts**. The extra money for the uplifts is allocated to, for example, the demand side (but not to the generators). The red rectangles contain the pricing schemes where a uniform price plus uplifts is defined, but the money for the uplifts comes from the generators. The redistribution of money among generators is done through an auxiliary optimization problem. Finally, the blue rectangles contain the pricing schemes that set up a high enough uniform price so that no participant requires additional compensations. Recall that the setting in Liberopoulos & Andrianesis [102] considers fixed demand, hence the price can be increased as much as needed to achieve revenue adequacy for all the generators.

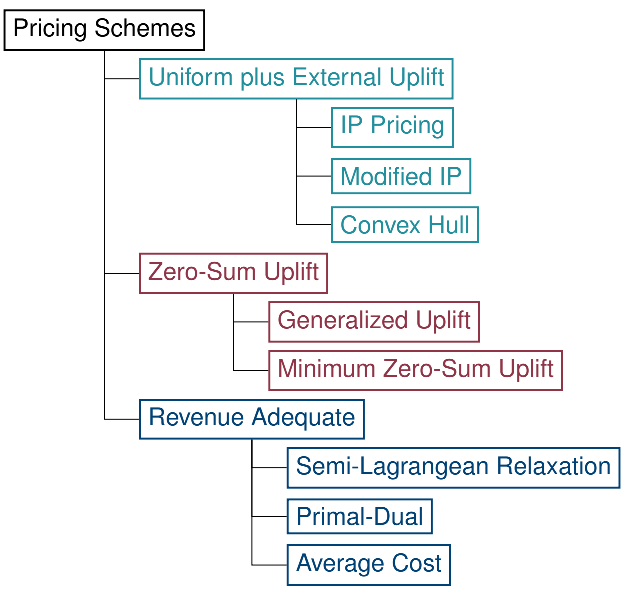


Figure 6: Overview of pricing schemes

If now a two-sided market is considered, the revenue adequacy property[5], which defines the schemes in blue, would come in conflict with the property of competitive equilibrium. As Figure 3 shows, a uniform price (as the ones given by the blue schemes) does not necessarily support a competitive equilibrium (in a two-sided market). On the other hand, the auxiliary problems used to define the prices for the red schemes become increasingly complex in more general settings. For example, Liberopoulos & Andrianesis [102] state that the minimum zero-sum uplift scheme is well understood only when there are just two generators and no active demand side, but not in more general cases. For those reasons, in practice most ISOs in the US implement variants of the green schemes. In the following, two of these concepts will be outlined: IP and CH pricing schemes.

IP Pricing: Introduced by O'Neill et al. [101], IP pricing is often regarded as Locational Marginal Pricing in a narrow sense. This scheme assumes that all resources are committed according to the optimal allocation. The locational uniform market price then equals the marginal cost of electricity at that particular location, according to the submitted bids. This may not correspond to the true marginal cost, as the commitment status of generators might change with marginally increasing demand and cause additional non-convex costs. However, the assumption to fix the resource commitments allows for a computationally efficient calculation, leveraging linear programming and duality theory. Since the uniform market price might not be high enough to recover the costs of some resources with non-convex costs, so-called make-whole payments are provided as uplifts. In particular, every generator is either rewarded or charged with an individual side-payment such that they incur zero net profits according to the bidding parameters. A variant of this method, referred to as IP+ pricing, waives the uplift charges and allows profitable generators to retain their surpluses.

A downside of both IP and IP+ pricing is their volatility with respect to the demand. Further, uplifts can be very high (see for example Figure 5 b) in the case of a two-sided market). In general settings, while the uplift payments ensure the revenue adequacy property, these side-payments might not be enough to incentivize all market participants not to deviate from the optimal allocation. Additional penalties or side payments might be necessary, often significant in size.

CH Pricing: In order to align incentives with minimum uplift payments, the CH pricing scheme was proposed by Gribik et al. [100]. Broadly speaking, the underlying non-convexities of the allocation problem are "convexified", yielding a computationally efficient pricing problem. Under mild conditions, it can be shown that these prices require minimal uplift payments to compensate for lost opportunity costs. However, describing the "convexified" problem can be a challenging task for real settings.

For this reason, MISO developed the Extended Locational Marginal Price (ELMP) as an approximation of CH pricing, in order to "improve price formation in the energy and ancillary services markets by more accurately reflecting the true marginal costs of supplying the system at each location" [103]. According to their report, their previous IP pricing based scheme did not allow fast start resources to set prices, even though those are needed to meet unsettled demand quickly.

ELMP considers a continuous relaxation of the allocation problem, yields prices based on duality theory, and calculates uplifts according to the opportunity costs of the market participants. This method has proven to provide solutions that are sufficiently close to (and in some settings identical to) actual CH pricing, while allowing for a more efficient computation [104].

Since most of the ISOs have implemented either versions of IP pricing or CH pricing, one could argue that the green schemes in Figure 6 are the most adaptable to real settings (particularly when considering two-sided markets). It is worth mentioning that the detailed pricing processes implemented by ISOs have been highly optimized over the years, adapting to their idiosyncrasies.

In summary, this section provides an overview on market design options, particularly focusing on allocation and pricing problems. Both elements are highly dependent on the bidding language used in the auctions. In order to better reflect the economics of generation resources in decarbonized energy markets as well as flexibility dimensions of the demand side, a more expressive bidding language is required. Furthermore, in

[5] Revenue adequate pricing schemes compute prices that ensure suppliers' costs are covered.

order to reduce costs of redispatch and welfare losses, local capacity constraints need to be considered. Various aspects of zonal and nodal pricing systems were discussed. Moreover, IP and CH pricing have been introduced as a reference for pricing schemes used in practice, and have been put in context to other mechanisms in Figure 6. However, ongoing research is conducted to refine and improve pricing schemes.

6 Strategic implications of market design options

Market outcomes are determined by the market's rules as well as the behavior of the market participants. The market participants' decisions depend on their individual preferences and goals, on the market rules, and also on their expectations about the behavior of others. Thus, a participant's strategy of how to act in the market is shaped by the market rules and the interdependence with other participants' strategies. Participants' behavior feeds back into the market outcomes, and expected behavior will influence how market rules are chosen.

Whether strategic behavior is detrimental or supportive for a given market may depend on the objective of the market designer. In what follows, ensuring short- and long-run economic efficiency as well as system security, while also supporting the expansion of RES, will be assumed as objectives (which may be in conflict).

This section will discuss selected implications of market design options on the market participants' strategies. It differentiates between effects of market design options on long-run investment, on market power, and on (undesirable) strategic bidding and gaming, although boundaries can be blurred. We classify behavior as (undesirable) strategic bidding or gaming if the actor takes advantage of unintended opportunities offered by the market design that counter the market's objectives; we classify such behavior as an exercise of, e.g., market power, if it is enabled by the market dominating position of the actor.

6.1 Effects on long-run investments

In the short run, generation and grid capacities as well as the technological composition are fixed. In the long run, new capacity can be built, existing plants can be shut down, and new technologies and solutions can be developed. Therefore, an adequate market design needs to set incentives for long-run efficient investment. Incentives for long-run investments are set by **prices that signal profitable investments** and invite firms to enter or exit, expand or shrink, or innovate. Investments into new developments such as better storage and demand flexibility options need to be incentivized and require access to price signals. Optimal location and technology choice as well as grid adjustments require access to information on local supply and demand. Thus, over- or underinvestment in relation to efficient investment concerns the local quantity of entry or exit, but also the technology mix of supply, the quantity, the location, the technology of demand flexibility and storage, and the grid expansion.

Multiple reasons might hinder price signals from generating optimal investments. First, optimal investments require firms to predict future prices and profit opportunities correctly, to have confidence in the reliability of regulatory decisions, and to coordinate their investments. Second, efficient locational choices require locally differentiated price signals. Such location-specific investment signals do not exist for large zonal pricing systems, in which local price differences are not revealed and costs for load adjustment may be mutualized (e.g., due to cost-based redispatch or counter-trading by system operators) [105, 106]. To the extent that the local price signals are distorted or due to market power or gaming (as discussed in the next subsections), investment incentives will also be distorted, leading to over- or underinvestment in transmission-constraint areas [55, 105, 107, 108, 109]. Misguided locational choices may require high public investments into the power grid to compensate for the inefficient locational distribution of generation [110]. Nodal prices support the identification of locations for profitable long-run investments by determining prices for every node in a network [111]. Zonal prices enable such identification only if there are no relevant transmission constraints within zones. Next to incentivizing investment into generation, appropriate location-specific investment signals can also incentivize local investment in flexibility options, which have the potential to relieve the power grid and to positively affect efficiency [112].

Thus, correct and informative price signals are decisive: "If we want the market to be guided by prices, and if we expect and intend for people to take these prices seriously, it becomes important to follow the usual advice to 'get the prices right' " [113]. Therefore, a market design should aim at generating the right price signals [114].

An alternative to relying on market price signals to guide investment decisions is a **centralized direct**

stimulation of investments or a regulation of prices and profits by the regulator. However, regulators can improve investment decisions only if they hold information superior to market signals or if market signals are distorted, hinting at a need to reorganize the market to send the appropriate signals. Here, also new digital information technologies may be used to create additional transparency regarding, e.g., costs.

An example where investment incentives are directly set is the realization of a desired change in the technological composition of supply. In Germany, nuclear phase-out will be completed in 2022, and coal-fired power plants will be paid for accelerating their shutdown with the aim to replace them by a less CO_2-intense technology mix.

Some challenges may require a regulator's direct intervention, such as the adoption of new technologies that are characterized by positive externalities (e.g., due to knowledge spillovers) not taken into account by an individual investor. Support payments for RES are designed to influence the quantity, the technology mix, and implicitly the location of renewable energy generation. Again, choosing an appropriate market design that steers the investment decisions in the desired direction is crucial.

Worldwide, long-run investments in renewable energy capacity are supported by governments. A common means of allocating this support are auctions. These auctions allocate the support for renewable energy to those bidders that are willing to realize their renewable energy projects with the lowest support payments. For successful bids, the auctions determine payments for each generated unit of renewable energy by this facility within a given time period, usually twenty years. The payments or support schemes can take various forms, among them fixed or sliding premiums and Contracts for Difference (CfDs). In Germany, bidders participate with pre-developed projects for building a facility with a certain installed capacity, and financial support is granted via a sliding premium.

When a **fixed premium** is auctioned, a winner receives that premium as a fixed amount in addition to the market price for each unit of generated renewable energy. When a **sliding premium** is auctioned, a winner receives the difference between the auction price and the average market price; if the market price is above the auction price, no premium is paid. When a **CfD** is auctioned, a winner receives the difference between the auction price (the CfD strike price) and the average market price – in contrast to the sliding premium, the premium turns into a payment if this difference is negative. Figure 7 illustrates the total revenues of the successful bidder (the firm that receives the support) for three different auction prices (vertical dimension) under the three different support schemes (horizontal dimension). Due to the differences between the support schemes, bids and auction prices under different schemes are not directly comparable.

One main difference between the support schemes is the market price risk that remains for the producer. With a fixed premium, the producer is exposed to all variations in market prices; with a sliding premium, the producer profits from market prices above the auction price but is protected from the downside risk; a CfD protects the producer from downward market price risk but denies any upside profits.

In case of high costs of financing the renewable energy projects and high risk premiums, the insurance that CfD schemes provide is an advantage [115, 116]. If, as is the case in Germany for offshore wind, an award in the auction is the only way to realize the project and get a (free) grid connection, a bid for a CfD is calculated based on the expectations about project costs and production volume. The main risk arises from the uncertain production volume. With a fixed or sliding premium, the bid is based on expectations about project costs, production volume, and about market prices. With all schemes, the bidders in their bids need to take into account that the respective risks affect all bidders in the same way and that winning the auction may be a signal of having based the bid on too optimistic expectations – of having fallen prey to the winner's curse [117, 118, 119]. As optimal bidding behavior to avoid the winner's curse in such auctions with a common-value component is demanding and empirical investigations show that bidders often do not succeed in avoiding it [120], a reduction in total risk that is likely provided by the CfD may be an advantage. Further, with lower risk, differences in bidders' risk attitudes become less important.

The insurance provided by the CfD, however, reduces incentives to take advantage of high market prices and to adjust operation based on the price signal (where the extent of the detachment of producers' operation decisions from market prices depends on details of the calculation of the CfD payments like the reference period, e.g., a hourly, monthly, or yearly averaged price, and the market of the reference price,

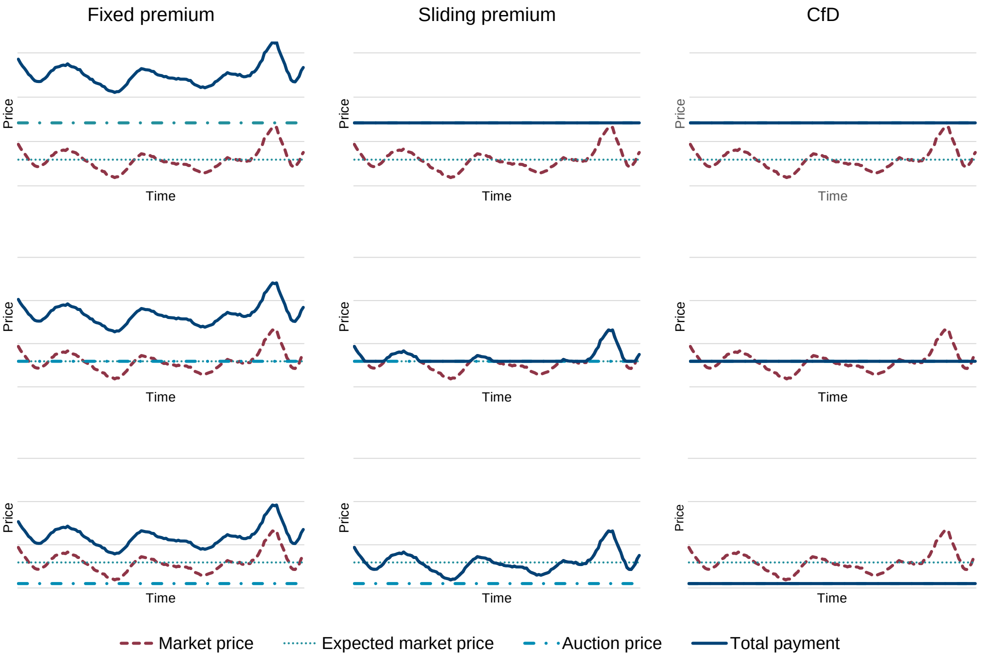


Figure 7: Illustration of the total revenue for a company per generated MWh if the firm's bid in an auction for renewable energy support has been awarded, when the support scheme is a fixed premium (left), a sliding premium (middle), or a CfD (right) for three different auction prices (horizontal dimension: above the market price, within the range of the market price, below the market price).

e.g., day-ahead or intraday [116, 121]). CfDs are used in the United Kingdom (UK). For wind power plant operators, the CfD in the UK has been complemented with the right for extra profits from selling stored wind energy at times of high market prices in order to incentivize investment in such storage and incentivize a supply shift using storage [122]. As this example from the UK shows, the insurance against market price fluctuations provided by the CfD can have undesirable consequences for investments and energy provision. A fixed or sliding premium avoids this lack of guidance by prices by preserving all chances to profit from high market prices. Another property of the fixed or sliding premium in auctions is that bidders can clearly express that they require no governmental support for their renewable energy project by means of a zero bid. Such bids have occurred in auctions for offshore wind, where bidders might even be willing to pay for the valuable access to the transmission grid [123]. On the one hand, this means that these schemes provide the opportunity for auction prices to signal when renewable energy sources need no further governmental support. In this case, with project costs below market prices, an auction for a CfD will result in a support level that requires producers to provide a net transfer to the government. On the other hand, as renewables become competitive at market prices and therefore bids and auction prices for support decrease, sliding premiums lose their insurance benefits [115, 116].

Disincentives to participate in a market can cause **underinvestment**. As an example, many countries faced low participation in auctions for RES for onshore wind [124, 125]. Support payments rose to the level of the reserve price, which is the maximum acceptable bid in the auction. Such payments were considered uncompetitive, and endogenous rationing was incorporated into the auction rules. Auctions with endogenous rationing collect bids and – in case all bids would win – reduce the auction volume or the reserve price according to pre-announced rules so that there is at least one losing bid. Endogenous rationing is meant to foster competition when competition is low. However, if – as is the case in these auctions – bidders need to bear bid-preparation costs in order to participate in the auction, the main effect of endogenous rationing is a reduction in participation [126]. This is because bidders – as a prerequisite to participate – need to expect to recover their bid-preparation costs in the auction, but endogenous rationing prevents such cost recovery for weak bidders in the auction, contributing to a downward spiral on participation. Low participation in these auctions puts the achievement of the long-run renewables development goals at risk.

6.2 Market power

Market power can be defined as a market participant's ability to influence prices to deviate from competitive prices to their advantage. It can be measured by Lerner's index [127], which calculates the deviation of the price from marginal costs, relative to the price. Market power can arise if an actor dominates the market due to his/her size, as measured by the Herfindahl-Hirschman Index of market concentration [128]. In electricity markets – where typically demand varies over time but not always responds to price signals, storage is limited, supply faces capacity constraints in the short run, and demand and supply need to be constantly balanced – market power of small actors can arise in situations where supply is scarce and the marginal participant faces no competition for the last units [129]. Then, market power can be exercised by **decreasing the offered quantity** or **increasing the offer price**.

The power to temporarily influence prices can be an element of a functioning market, if it is limited in duration and extent. An example are the peak load prices above marginal variable costs that cover capacity costs and incentivize long-run investment [130, 131, 132]. Limits to exercise such influence on prices are general or individual offer caps (e.g., as with automated mitigation mentioned below). However, setting exogenous price or bid caps optimally is a challenge. The need for exogenous caps stems from the decoupling of demand from supply, such that demand cannot react to price signals. Integrating demand into the market can address this issue.

Ideally, the signals sent by prices steer the market as desired by the designer, for example they incentivize efficient short-run operation of existing generation units and efficient long-run investments. To achieve short-run efficiency, the demand side should pay the marginal social cost of energy and the supply side should be paid marginal social value (including externalities, for example due to CO_2 emission). If a system generates such prices, market power and market failure is avoided. However, depending on the market design, actors' size, and actors' information, manifold opportunities to exercise market power may arise.

Plant operators might be able to raise the price in the day-ahead market by withholding supply. Such behavior has been identified for the Iberian market, where large dominant plant operators withheld quantity in the day-ahead market to profit from the resulting higher prices. The profitability of this behavior was counteracted partially by small actors who used some of the arbitrage opportunities from the price differences between day-ahead and intraday markets [133]. In general, **liquid forward markets** and long-term fixed-price contracts can strengthen competition and reduce incentives for tacit collusion [134, 135, 136, 137, 138]. Collusive behavior might be identified or even prevented using new possibilities of information technologies, e.g., by machine learning or cryptographic certification of load profiles.

Market power can be prevented by **inviting participation by more or different firms**, because an increased diversity and number of actors reduce a firm's ability to execute market power. A potential means to lower the barriers to market participation for smaller firms in the future are information technologies (e.g., by means of increasing the transparency, knowledge-sharing, and automation in the energy system as discussed in Section 3). As an example of increasing actor diversity, inviting purely financial traders into the market is considered a means to prevent price differences between day-ahead and intraday markets [136, 139]. They are meant to use any arbitrage opportunities and thereby eliminate the plant operators' possibilities to profit from price distortions. This works only if transaction cost are sufficiently low, traders have sufficient capital, and these financial traders do not also participate in multiple connected markets, facing themselves the opportunity to profit from price differences between markets [139]. Section 6.3 discusses opportunities for influencing prices and profits when the same good is traded in sequential markets.

Another example of a design option that increases competition by inviting participation is the shift from a closed capacity and energy auction for balancing energy to a **market for balancing energy**, stipulated by the European Commission [140]. As discussed in Section 4, in auctions for balancing energy in Germany before November 2020, balancing service providers submitted both a capacity bid and an energy bid. The providers with the lowest capacity bids based on the capacity-bid merit order received a capacity payment equal to their capacity bid. Furthermore, in case of an activation of balancing energy, they received an energy payment equal to their energy bid if their energy bid put them in a sufficient position in the energy-bid merit order. In these auctions, the last (highest) energy bids in the merit order used to be extremely high. Due to their position in the merit order, they were rarely activated, and the associated bidders made profits only from their capacity bid. Nevertheless, in the rare times when these bids were activated, the price for balancing energy was very high. As pointed out in Section 4, the recent introduction of a market for balancing energy (for aFRR and mFRR) in Germany implies that, after the auction, additional real-time energy bids are allowed by plant operators whose capacity bids have not been awarded or who did not participate in the auction. Allowing for such additional energy bids can destroy collusive bidding in the auction, and increase the number and diversity of providers of balancing energy. However, details in the design matter, and whether introducing a market for balancing energy resolves the problem of high energy bids will depend on its precise design. The German market, for instance, allows recipients of capacity payments to participate in the intraday market if their energy bid is outbid, thus creating an outside option that can incentivize even higher energy bids, reinforcing the problem the market for balancing energy was meant to address [141].

We also note that grid transmission constraints may separate markets into small local markets and enable the exercise of market power. Different pricing schemes like **nodal and zonal pricing differ in the extent of market power they enable** and in the ways market power is exercised.

A market with nodal pricing directly calculates an allocation that takes local differences in load and generation into account and respects transmission constraints. As a result, if suppliers bid marginal costs and the demand side bids marginal values, prices reflect local value and costs of energy and can provide incentives for investment in transmission grids or for the reallocation of load and generation. As transmission constraints may limit competition between electricity providers on different sides of a congested line, market power can arise [142]. Providers that are activated only in case of an import restriction into their area have an incentive to bid high prices [143]. Further, a provider may offer a lower quantity at a high price in order to induce a constraint on the transmission lines into his/her area and profit from the high price [144]. In the short run, generation obligations, price and offer caps, and automatic bid replacement according to pre-negotiated maximum bids in case of otherwise high prices due to transmission constraints (automated mitigation) can address this issue and reduce incentives to exercise market power [143, 145]. Integrating demand flexibility at the same granularity as supply into the market is another, and usually a preferable, means to mitigate market power [107]. In the long run, grid expansion and the removal of bottlenecks reduce opportunities for local market power. In fact, an efficient expansion of the grid might focus on decreasing transport restrictions to a level that supports competition rather than to a level that enables all previously restricted flows [144].

Similarly, transmission constraints can limit competition and enable the exercise of market power in the market for redispatch in a market design with zonal pricing and market-based redispatch [146]. Redispatch costs are not assigned to the transport restrictions, thereby masking bottlenecks and preventing locational price differences that would incentivize long-run adjustments to reduce permanent transport restrictions [107].

Germany can learn from a wide variety of experiences made worldwide. However, details in the design, the potential participants, and the infrastructure matter. Consequently, careful exploration is necessary to assess in how far positive experiences and methods to handle market power from other countries are transferable to Germany.

6.3 (Undesirable) Strategic bidding and gaming

Bidding mechanisms have the aim to generate prices and allocations based on competition, thereby aggregating and using distributed private information held by bidders. To achieve this aim, they provide incentives to submit bids that are calculated based on the bidders' private information. For plant operators, the relevant private information is mostly the marginal costs of production, which includes opportunity costs or ramping costs. In settings with sufficient competition and single-unit bids, standard auction procedures like auctions with a uniform price determined by the best unsuccessful bid (the Vickrey auction), with a uniform price determined by the worst successful bid, or with a pay-as-bid rule where each successful bid determines its price, achieve this aim [147]. If, however, a bidding mechanism provides incentives to base bids mainly on other factors, such as driving up prices for all units by submitting high bids on some units or driving prices up in one market to generate arbitrage opportunities in other markets, they are prone to what is sometimes called gaming or – slightly misleading, because also the intended bidding behavior requires strategic considerations – (undesirable) strategic bidding.

Opportunities for gaming arise when actors participate in multiple connected markets for the same goods, when they participate with multiple units in one market, or when they can participate under multiple or flexible identities. In all these cases, they may be able to adjust their behavior in one market, with respect to one unit, or under one identity so that they can more than offset potential losses or costs by increased profits in the other market, with respect to the other units, or under another identity, respectively. Further, market rules need to be stable with respect to incentives to build coalitions or to tacitly cooperate and influence the market outcome. Some of these impacts on the market outcome could also be categorized as an execution of market power. Some opportunities for (undesirable) strategic bidding and gaming seized in the past will be illustrated in this section.

6.3.1 Bidding in sequential markets

Incentives to influence prices in one market in order to generate profits in another market may arise when the same actor can participate in two subsequent interrelated markets that both allocate contracts for the same final energy provision but only the later market takes allocation constraints into account. Generating and capitalizing on such arbitrage opportunities has been termed **Increase-Decrease (Inc-Dec) gaming**. Inc-Dec gaming has affected for instance the Californian and the British markets in the past [55, 148].

A setting in which Inc-Dec gaming occurs is a day-ahead market with a subsequent market for redispatch (or counter-trading) [109]. If market participants are the same in both markets and transmission constraints can be foreseen, participants may bid to exacerbate transmission constraints and profit from higher redispatch payments. On the one hand, a plant operator that expects that his/her unit might need to be shut down to respect transmission constraints may want to bid low in the day-ahead market to ensure a sale. She/he could then buy back the energy in the redispatch market at a lower price and earn the difference. On the other hand, a plant operator that expects that his/her unit might need to run to respect transmission constraints may want to withhold the unit (or bid very high) in the day-ahead market in order to sell the energy for a high price in the redispatch market. Creating arbitrage opportunities with such a strategy becomes possible due to constraints that need to be respected, that require differentiated prices, and that are foreseeable. The low or high bids in the day-ahead market reflect the opportunity costs faced by the market participants due to local price differences and predictably higher profits in the redispatch market, which create the arbitrage opportunities. Evidence from Italy shows that thermal generation unit owners appear to employ Inc-Dec strategies, adjusting their offers by about 50 EUR/MWh or more when a transmission constraint becomes predictable [149]. Nodal pricing has been suggested to mitigate such Inc-Dec gaming, because it takes transmission constraints directly into account in the wholesale market and sequential redispatch is not necessary [146, 150].

Another example of Inc-Dec gaming is with financial traders that are suspected to have increased congestion through their forward bids, incurring losses in the day-ahead market in order to increase profits from their FTRs, which give them a share of the congestion charges that arise when transmission is constrained [139]. Restricting the share of identical participants in subsequent markets for the same good might prevent the strategic generation of arbitrage opportunities.

While there is a need for several sequential electricity markets in order to refine supply schedules, to adjust to cyclic and stochastic demand, and to ensure a balance of supply and demand at any point in time, there exist different market designs with respect to forward markets, day-ahead, intraday and real-time markets, or the use of reserves and directives [67]. These variations differ in the information they generate and reveal, the way markets are interconnected, and the power given to actors like system operators. Therefore, they differ in the opportunities for strategic gaming.

6.3.2 Gaming in interconnected markets

Incentives for **strategic demand shifts between connected markets** can arise in various ways. An example of a demand shift enabled by two connected markets occurred in June 2019 in Germany and almost led to a blackout. Two balancing group managers that were responsible for balancing supply and demand within their balancing groups did not buy the required amount of short-term power supply at the intraday market. Instead, the balancing group managers relied on balancing by the system operators using balancing energy, because they anticipated that their payments for balancing energy would be lower than for the power they could buy at the intraday market. As a result, six GW of power had to be procured in the short-term. The reason for the incentive to shift demand to balancing energy was a change in the market for balancing energy that created a low energy price in this market. This, and the interconnection between the markets led to behavior that endangered supply security and system stability [151]. Thus, a market's design needs to incentivize participation of the relevant actors, and changes in one market's rules need to take into account its interconnections with other markets.

A related case of strategic demand shift has been suspected to have occurred in the Nordic electricity market. Transmission could be constrained for example between Norway and Sweden and within Sweden, but these two types of constraints resulted in different payment streams for the TSO. In case of a constraint between Norway and Sweden, a difference in prices at the two nodes of the constraint resulted in a transmission fee for energy transported on the constraint, received and split by the Norwegian TSO and the Swedish TSO. In case of a constraint within Sweden, the system operator had to incur costs to resolve the constraint by counter-trading, with costs charged in parts to network users. Thus, the Swedish TSO had an incentive to declare constraints to be between countries [152].

6.3.3 Other gaming incentives

Possibilities for (undesirable) strategic bidding arise if one market participant takes part in a bidding process with multiple units. In multi-unit auctions with multi-unit bidders, bidders have an incentive for supply (or demand) reduction [147, 153]. In a multi-round auction in which all selling prices decrease as long as supply exceeds demand, a bidder that offers multiple units of supply may decide to decrease supply early in order to end the auction and profit from high selling prices for the other units. In a sealed-bid uniform-price auction, the supplier may bid much more than his/her costs on units that are likely to determine the uniform price for all of his/her units in case of an award.

Opportunities for gaming may arise if a market discriminates between participant types and types are modifiable or cannot be verified. Regulators sometimes aim at influencing the composition of market participants, for example by privileging technologies or participant types. An example for the latter kind of discrimination is the privileged treatment of *Bürgerenergie* (citizen energy) in Germany's auctions for RES. The aim is to improve civil acceptance of wind energy by facilitating successful wind energy projects operated by local communities. The preferential treatment in the auctions for onshore wind, in particular the extended time frame for the realization of the project and the reduced up front requirements for securities and permits, led to a large number of successful projects by local communities. However, these successful projects were generated in parts by firms that built partnerships with the communities in order to profit from the preferential treatment [154]. In three auctions in 2017, 71 to 89 % of the bid volume came from the privileged types, with most of them taking advantage of the relaxed requirements. These bids won 59 to 99 % of the awarded volume. Thus, one main effect was a shift of supply from firms to communities that bid in place of the firms. The resulting large number of projects with long time horizons for realization, low securities, and missing permits might lead to low realization rates. Precluding flexibility in participants' types is therefore a major issue when participant types are favored.

New challenges for long-run investment incentives, market power prevention, and disincentives for gaming may arise when the objective of a high share of renewable energy has been achieved. Including demand flexibility and storage into the market will change its shape. To address these changes, new designs will need to be developed. In general, as can be seen from the examples in this section, small changes in the design can have huge effects on incentives and, thereby, on outcomes. Thus, details matter, and the rules have to be concerted to result in a coherent and robust market design.

7 Policy implications and discussion

Several policy implications can be drawn from the analyses in the previous sections.

Changing demand and new (technological) opportunities should lead to a rethinking of electricity market design. The shift to generation from RES leads to operating conditions under increased variability of supply over space and time. Also, new actor groups, such as electric vehicles, decentral storage devices, but also sector coupling processes, and links to other (gaseous) energy carriers need to be integrated effectively into the electricity market. Moreover, electricity markets need to consider the location of decentralized resources and actors in the grid. The active coordination of such an increasing number of actors in a single (European-wide) interconnecting grid, which imposes its own technical limitations, could become feasible with new information technologies. This is mainly due to large-scale automated trading mechanisms that successfully accommodate an increasing number of market participants. Information technologies further enhance the governance of decentralized systems through increased transparency and swift information exchange. The electricity market design needs to take these changing circumstances and enabling conditions into account, in order to safely and efficiently operate the central puzzle piece of the future coupled energy systems.

Central to such a market redesign are locationally and temporally fine-grained prices signaling to all market parties their marginal impact on the system. As discussed in Section 6, a shift to prices with a locational component seems to be necessary to efficiently deal with grid congestion, and to let new types of market participants take part and be integrated into the electricity market, while supporting system stability. Generation of electricity and actively controlled demand will be distributed to a far higher degree between a larger number of market participants. Locally and temporally fine-grained prices and markets will be needed to achieve coordination and align incentives over time and space appropriately. This also includes the use of more accurate price signals, instead of, e.g., averaged prices.

The current system and half-measure reforms of locally matching supply and demand do not hold up to this task. The current practice of cost-based redispatch will not be applicable to many of the future market participants, as it is a command-control policy, which then compensates redispatched actors on a cost basis. These costs can be relatively well estimated for conventional power plants, which are active in the power market. However, many new actors that will be needed to locally balance the grid have no clear cut cost basis, but instead have opportunity costs and economic preferences. Demand response processes and electric vehicles may prefer to charge in one period, but may or may not be able to shift their consumption. Sector coupling processes will be constrained by additional conditions unrelated to the power sector. Hence these opportunity costs will generally be non-determinable by regulators. The alternative mechanism of market-based redispatch suffers from perverse incentives, results in the infamous Inc-Dec gaming, and the break-down of liquidity in markets.

Furthermore, studies reveal that some European markets with all their technologies and participants would currently profit from locational marginal pricing [83] and may constitute successful pilot examples. While concerns exist that LMPs and zonal splits could lead to adverse welfare effects for some market parties, these are often projected to be smaller than existing differences in network tariffs, and could be addressed via additional policies, such as an allocation of FTRs to existing installations [155].

Therefore, the central question becomes whether the shift to locational marginal pricing should be incremental, thus taking place via splitting up into smaller zones first, or whether one big step from zonal pricing to finely grained LMPs is more feasible and has positive welfare implications. As outlined in Section 5, several issues with successive splitting up of zones for short- and long-term markets speak for a one-step approach. The underlying reason is that markets with LMPs need to be set up as a coherent short- and long-term trading framework that inherently addresses potential pitfalls with smaller pricing zones.

With respect to long-term markets, frequent re-zoning undermines the basis for long-term markets, as the underlying price variable of financial contracts is frequently redefined, and re-zoning is subject to intense political debates, which are, as political decisions with high discretion, difficult to quantify for market actors [88]. Also, the transformation across all energy sectors requires significant investments in RES, storage, and loads. Major challenges will be to have sufficient investment signals in place to foster an efficient local allocation of these resources. This implies that financial incentives with local components need to be considered to induce investors to choose grid-friendly locations. Furthermore, in meshed networks as in Germany, optimal zone definitions are inherently instable and necessarily change over time as the energy transition progresses and the power mix changes [90]. Regarding short-term markets, the current market framework with intraday continuous trading and bilateral matching relies on liquidity within zones, which will be diminished by the splitting of zones [156].

In contrast, a market design for LMPs addresses both issues: for long-term markets the underlying prices are clearly defined as the prices at physical nodes.[6] For long-term contracts in the US, trading hubs are defined as weighted averages of nodal prices, which allow to gather liquidity for long-term trading. Even if the significance of different hubs may shift over time, in contrast to re-zoning, prices remain clearly defined. The regular auctioning of FTRs can be used to cover remaining differences between liquid hub prices and individual locational prices [44]. Such a long-term market framework is also important for addressing potential market power issues (cf. Section 6.2). Support schemes such as CfDs for renewable technologies could address the market risks these actors face, while LMPs would make the contribution of different locational choices more transparent.

For short-term markets, the use of auctions that integrate transmission constraints into the clearing ensures that liquidity is given even in the real-time time frame, allowing a new robust reference market to be established – note, however, that market power may still occur and should be addressed appropriately [44]. Such a real-time market can be the basis for longer-term markets, including intraday markets and day-ahead trading to refer to and settle against. The establishment of a fine-grained real-time price signal that considers transmission constraints as a reference market also has other fundamental benefits: It represents the value of electricity at (or at least as close as possible to) the only moment and place that is truly decisive, that is the moment and place of delivery. By incorporating the technical constraints (grid constraints and operational constraints of units) integrally in the market clearing, less time and security buffers need to be in place to correct for technically infeasible market results. A robust real-time price signal (or more precisely the expectation thereof) then propagates back to earlier intraday, day-ahead, and long-term markets, and as a robust underlying allows for the definition of traded products, e.g., options, that give a value to local flexibility, even in the long-term. In addition, available information technology capacities may assist market participants in efficiently handling real-time prices.

The step from zonal pricing to locational marginal pricing has been successfully taken in the PJM market [157], as well as in the ERCOT market, with limited transaction cost – while there is currently no historic precedent for a successful transition to LMPs via sequential zone splitting. Thus, historic examples exist from which to learn from when switching to LMP markets. Finally, commercially available systems to organize and run LMP markets already exist today.

While successive zone splitting may have adverse effects, other steps may prove beneficial for both current markets and future locationally resolved markets. This encompasses the use of auctions and advanced bidding formats as well as the organization of balancing obligations.

> First, an increased use of auctions not only in the day-ahead frame, but also in the intraday frame offers a more efficient use of existing cross-border capacity, as it does not need to rely on bilateral matching in continuous trading [156].

> Second, this allows for the introduction of multi-part bids and efficient pricing mechanisms, discussed in Section 5, which enable market participants to better express their capabilities and deal with uncertainty of clearing prices [71], while clearing speed and the efficiency of the solution is improved on the side of market places (cf. Section 5.2).

[6] This even applies if locational marginal pricing extends to lower-level networks, which must be appropriately integrated into the system where in the transmission network nodal prices are applied.

GEFÖRDERT VOM
Bundesministerium für Bildung und Forschung

> Third, the concept of physical balancing groups may be abolished in favor of individual balancing responsibility (with a corresponding reform of imbalance pricing) and financial pooling of imbalance portfolios (cf. Section 5.2).

> Fourth, policymakers should increasingly become aware of the potentials of new energy and information technologies and best make use of them in the governance and coordination of decentralized electricity systems.

Finally, Germany should consider being a front-runner in the adoption of local marginal pricing, while also being supportive of other countries aiming to adopt it. Being a front-runner fits the ambitious targets on the energy system and technology developments that Germany has set itself, without harming the European market. This would also have the advantage of setting the standards and developing the technologies that other countries would later adopt, including novel digital solutions and use cases. While it may be challenging to be a first-mover, being centrally located with many interconnections to neighboring countries, several proposals for coupling zonal and nodal systems exist, and may be further refined in the process of market implementation [89]. While congestion management will also be needed on the level of the distribution grid, introducing nodal prices on the transmission grid already provides a robust basis for further developments at the lower grid levels, as well as a part of the necessary local incentives and clear interfaces for DSOs (cf. Section 5.2).

The least that should be done is to be supportive of the use of LMPs in neighboring countries, as this can provide important insights for Germany itself. Next to market, technological, and digital lessons, much may also be learned in terms of successful best practices of institutional arrangements. While adequate competences of both TSOs (currently accounting for, e.g., system operation, network planning, and network expansion) and power exchanges (currently jointly developing the clearing algorithms and providing access to the markets) are needed under locational marginal pricing, the current definition of the actor roles and responsibilities (including those of market participants) may need to be rethought under locational marginal pricing. Such an analysis should also look at incentives that are present for different actors under the current pricing regime and a locational marginal pricing regime. Finally, also questions regarding a financial regulation of different actors will have to be investigated.

8 Conclusion

Taking into account a variety of economic, techn(olog)ical, and strategic aspects of electricity systems, this whitepaper provides a guideline towards a future-proof electricity market design that successfully integrates a large share of RES. Moreover, a huge variety of new market players offering, e.g., storage or demand flexibilities, are to be considered. However, transitioning towards a renewable-based electricity system involves a set of challenges including, e.g., intermittent and decentralized electricity generation, corresponding uncertainties regarding returns on investment, as well as longer transmission distances between generation and demand centers (where transmission capacities are typically highly limited). In this whitepaper, different electricity market design options that govern an appropriate use of new information and energy technologies provide possible solutions to these challenges.

More specifically, recent developments in energy technologies may enable, for example, a better use of demand-side flexibilities in industrial production processes and a better integration of prosumers into the electricity system. On the side of new information technologies, overall market efficiency may increase through additional transparency as well as newly gained information and knowledge. Automated electricity trading may allow market participants to react to changing market conditions almost in real time. To fully exploit the potential of both new information and energy technologies, this whitepaper proposes refined allocation and pricing rules on day-ahead and intraday markets that successfully account for recent technological developments and new market players (e.g., prosumers or automated software agents).

In particular, focusing on the German electricity system, the current uniform pricing scheme does not account for transmission and distribution constraints as well as possible network congestion – an increasingly relevant issue. Thus, more fine-granular prices may be better suited to reflect the network topology and, therefore, contribute to more efficient electricity market outcomes and dispatches. A nodal pricing system 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. Again, information technologies may facilitate the implementation and governance of decentralized or nodal systems. However, significant concerns may arise with respect to regional disparities, market power, and liquidity. Moreover, there are general questions regarding concrete implementation strategies of nodal pricing, e.g., the speed of implementation and possible first-mover disadvantages in the context of coupled markets within Europe with respect to learning and experimenting with the new market design.

While the debate about abandoning uniform pricing is still ongoing in Germany, this whitepaper argues that the benefits of transitioning towards nodal prices quite likely outweigh the associated long-run costs. Here, Germany may also learn from other countries with nodal pricing schemes and avoid potential pitfalls early on. When implementing nodal pricing, this whitepaper argues in favor of a one-step transition instead of increasing the granularity of bidding zones incrementally step-by-step. 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.

By providing explicit policy recommendations regarding future allocation and pricing rules and the incorporation of recent technological developments in electricity market design, this whitepaper assists policy-makers in paving the way towards efficient electricity systems that successfully accommodate a high share of RES. First, this whitepaper highlights that efficiently dealing with network congestion requires shifting to price rules with a locational component and accommodating new market participants, such as demand response actors, through adequate bidding languages. Second, rather than incrementally transitioning to LMPs, the whitepaper argues in favor of a one-step procedure as described above.

Against this background, it is important to note that the whitepaper only provides first guidance for policymakers when developing a future-proof electricity market design. Some aspects of this work including, e.g., the governance of the transition towards nodal prices, will have to be analyzed and specified in more detail. Related aspects will be elaborated on in a second whitepaper. Moreover, future work will also have to focus more on the actually required regulatory changes (including financial market regulations) and possible (re-)distributions of welfare that are linked to different pricing schemes. In order to promote international collaboration of researchers in the relevant field, expert workshops involving participants from various countries will continuously be conducted within the SynErgie project to share experiences worldwide.

In summary, while there might be a number of challenges in the transition, our analysis suggests that with a large share of renewable energy providers the move to a locationally and temporally differentiated price system is required for an efficient and robust electricity market of the future.

References

[1] Federal Ministry of Economic Affairs and Energy. Wie unser strom bis 2050 klimaneutral werden soll, 2021. https://www.bmwi-energiewende.de/EWD/Redaktion/Newsletter/2020/10/Meldung/topthema.html.

[2] EPEX SPOT. Epex Spot Trading Products.

[3] Bundesnetzagentur. Quartalsbericht netz- und systemsicherheit - zweites quartal 2020. Retrieved December 28, from https://www.bundesnetzagentur.de/SharedDocs/Mediathek/Berichte/2020/Quartalszahlen_Q2_2020.pdf?__blob=publicationFile&v=4, 2020.

[4] Thomas Bründlinger, Julian Elizalde König, Oliver Frank, Dietmar Gründig, Christoph Jugel, Patrizia Kraft, Oliver Krieger, Stefan Mischinger, Dr. Philipp Prein, Hannes Seidl, Stefan Siegemund, Christian Stolte, Mario Teichmann, Jakob Willke, and Mareike Wolke. dena-Leitstudie Integrierte Energiewende. Technical report, Dena, 2018.

[5] European Commission. Regulation (eu) 2019/943 of the european parliament and of the council of 5 june 2019 on the internal market for electricity, 2019. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019R0943.

[6] Ahmed T. Elsayed, Ahmed A. Mohamed, and Osama A. Mohammed. DC microgrids and distribution systems: An overview. *Electric power systems research*, 119:407–417, 2015.

[7] Animesh Jha. *Superconductor Technology*. John Wiley and Sons, 1998.

[8] Best Paths. Superconducting cables: Entering the power grid world. Retrieved November 14, from http://www.bestpaths-project.eu/en/news/superconducting-cables-entering-the-power-grid-world, 2020.

[9] Seama Koohi-Fayegh and Marc A Rosen. A review of energy storage types, applications and recent developments. *Journal of Energy Storage*, 27:101047, 2020.

[10] Oliver Schmidt, Sylvain Melchior, Adam Hawkes, and Iain Staffell. Projecting the future levelized cost of electricity storage technologies. *Joule*, 3(1):81–100, 2019.

[11] Richard Van Noorden. The rechargeable revolution: A better battery. *Nature News*, 507(7490):26, 2014.

[12] Gilbert Fridgen, Robert Keller, Marc-Fabian Körner, and Michael Schöpf. A holistic view on sector coupling. *Energy Policy*, 147:111913, 2020.

[13] Clark W. Gellings. Evolving practice of demand-side management. *Journal of Modern Power Systems and Clean Energy*, 5(1):1–9, 2017.

[14] Alexander Sauer, Eberhard Abele, and Hans Ulrich Buhl. *Energieflexibilität in der deutschen Industrie: Ergebnisse aus dem Kopernikus-Projekt-Synchronisierte und energieadaptive Produktionstechnik zur flexiblen Ausrichtung von Industrieprozessen auf eine fluktuierende Energieversorgung (SynErgie)*. Fraunhofer Verlag, 2019.

[15] Leon Haupt, Marc-Fabian Körner, Michael Schöpf, Paul Schott, and Gilbert Fridgen. Strukturierte analyse von nachfrageflexibilität im stromsystem und ableitung eines generischen geschäftsmodells für (stromintensive) unternehmen. *Zeitschrift für Energiewirtschaft*, 44(2):141–160, 2020.

[16] Raphael Heffron, Marc-Fabian Körner, Jonathan Wagner, Martin Weibelzahl, and Gilbert Fridgen. Industrial demand-side flexibility: A key element of a just energy transition and industrial development. *Applied Energy*, 269:115026, 2020.

[17] Charles E. Leiserson, Neil C. Thompson, Joel S. Emer, Bradley C. Kuszmaul, Butler W. Lampson, Daniel Sanchez, and Tao B. Schardl. There's plenty of room at the top: What will drive computer performance after moore's law? *Science*, 368(6495), 2020.

[18] David Rotman. We're not prepared for the end of moore's law. Retrieved November 14, from `https://www.technologyreview.com/2020/02/24/905789/were-not-prepared-for-the-end-of-moores-law/`, 2020.

[19] Gordon E. Moore et al. Cramming more components onto integrated circuits, 1965.

[20] Gordon E. Moore et al. Progress in digital integrated electronics. In *Electron devices meeting*, volume 21, pages 11–13, 1975.

[21] Tibi Puiu. Your smartphone is millions of times more powerful than the apollo 11 guidance computers. Retrieved December 22, from `https://www.zmescience.com/science/news-science/smartphone-power-compared-to-apollo-432/`, 2020.

[22] Howard A. Daniels and Neela Mayur. More than mainframes: Power utilities are finding that the mix-and-match trend that is evident in computer systems is for them a matter of survival. *IEEE Spectrum*, 22(8):54–61, 1985.

[23] Antonios Gouglidis, Benjamin Green, David Hutchison, Ali Alshawish, and Hermann de Meer. Surveillance and security: protecting electricity utilities and other critical infrastructures. *Energy Informatics*, 1(1):15, 2018.

[24] Gartner. 5 trends drive the gartner hype cycle for emerging technologies. Retrieved November 14, from `https://www.gartner.com/smarterwithgartner/5-trends-drive-the-gartner-hype-cycle-for-emerging-technologies-2020/`, 2020.

[25] Michael E. Porter and James E. Heppelmann. How smart, connected products are transforming competition. *Harvard business review*, 92(11):64–88, 2014.

[26] Rokia Bouzidi, Fahima Nader, and Rachid Chalal. Towards a classification of information technologies. In *Proceedings of the International Conference on Computing for Engineering and Sciences*, pages 24–28, 2017.

[27] Stephan Berger, Marie-Sophie Denner, and Maximilian Roeglinger. The nature of digital technologies-development of a multi-layer taxonomy. In *Proceedings of the 2018 European Conference on Information Systems*, 2018.

[28] Janusz J. Sikorski, Joy Haughton, and Markus Kraft. Blockchain technology in the chemical industry: Machine-to-machine electricity market. *Applied energy*, 195:234–246, 2017.

[29] Simon Albrecht, Stefan Reichert, Jan Schmid, Jens Strüker, Dirk Neumann, and Gilbert Fridgen. Dynamics of blockchain implementation-a case study from the energy sector. In *Proceedings of the 51st Hawaii International Conference on System Sciences*, 2018.

[30] Esther Mengelkamp, Benedikt Notheisen, Carolin Beer, David Dauer, and Christof Weinhardt. A blockchain-based smart grid: towards sustainable local energy markets. *Computer Science-Research and Development*, 33(1-2):207–214, 2018.

[31] Key Pousttchi, Alexander Gleiss, Benedikt Buzzi, and Marco Kohlhagen. Technology impact types for digital transformation. In *2019 IEEE 21st Conference on Business Informatics (CBI)*, volume 1, pages 487–494. IEEE, 2019.

[32] Focus Magazine. The future of sensor technology. Retrieved November 14, from `https://www.te.com/global-en/industries/sensor-solutions/insights/the-future-of-sensor-technology.html`, 2020.

[33] Research and Markets. Top 10 technologies in sensors & instrumentation 2018. Retrieved November 14, from `https://www.prnewswire.com/news-releases/top-10-technologies-in-sensors--instrumentation-2018-300650505.html`, 2018.

[34] Walid Saad, Mehdi Bennis, and Mingzhe Chen. A vision of 6g wireless systems: Applications, trends, technologies, and open research problems. *IEEE network*, 34(3):134–142, 2019.

[35] Markets and Markets. High performance data analytics (hpda) market by component (hardware, software, and services), data type (unstructured, semi-structured and structured), deployment model (on-premises and on-demand), vertical, and region - global forecast to 2021. Retrieved November 14, from `https://www.marketsandmarkets.com/Market-Reports/high-performance-data-analytics-market-39751632.html`, 2020.

[36] Genoveva Vargas-Solar, José-Luis Zechinelli-Martini, and Javier-Alfonso Espinosa-Oviedo. Big data management: what to keep from the past to face future challenges? *Data Science and Engineering*, 2(4):328–345, 2017.

[37] Oliver D. Doleski. *Realisierung Utility 4.0 Band 2: Praxis der digitalen Energiewirtschaft vom Vertrieb bis zu innovativen Energy Services*. Springer, 2019.

[38] Deutsche Energie Agentur. dena-report: Artificial intelligence for the integrated energy transition. Retrieved November 14, from `https://www.dena.de/en/newsroom/publication-detail/pub/dena-report-artificial-intelligence-for-the-integrated-energy-transition/`, 2020.

[39] Bundesministerium für Wirtschaft und Energie. Blockchain-Strategie der Bundesregierung. Retrieved November 14, 2020, from `https://www.bmwi.de/Redaktion/DE/Publikationen/Digitale-Welt/blockchain-strategie.pdf?__blob=publicationFile&v=8`, 2019.

[40] Huawai. Virtual reality/augmented reality white paper. Retrieved November 14, from `https://www-file.huawei.com/-/media/corporate/pdf/ilab/vr-ar-en.pdf`, 2017.

[41] Stjepan Sučić and Tomislav Capuder. Automation of flexible distributed multi-generation systems by utilizing optimized middleware platform. *Applied energy*, 169:542–554, 2016.

[42] Lion Hirth, Jonathan Mühlenpfordt, and Marisa Bulkeley. The entso-e transparency platform–a review of Europe's most ambitious electricity data platform. *Applied energy*, 225:1054–1067, 2018.

[43] Joanne Roberts. From know-how to show-how? Questioning the role of information and communication technologies in knowledge transfer. *Technology Analysis & Strategic Management*, 12(4):429–443, 2000.

[44] Georgios Antonopoulos, Silvia Vitiello, Gianluca Fulli, and Marcelo Masera. *Nodal pricing in the European internal electricity market*, volume 30155 of *EUR*. Publications Office of the European Union, Luxembourg, 2020.

[45] Francisco Jaview Carillo and Francisco Javier Carrillo. From transitional to radical knowledge-based development. *Journal of Knowledge Management*, 2006.

[46] Johannes Sedlmeir, Hans Ulrich Buhl, Gilbert Fridgen, and Robert Keller. The Energy Consumption of Blockchain Technology: Beyond Myth. *Business & Information Systems Engineering*, 62, 2020.

[47] Peter Cramton. Electricity market design. *Oxford Review of Economic Policy*, 33(4):589–612, 2017.

[48] Daniel Sadi Kirschen and Goran Strbac. *Fundamentals of power system economics*. John Wiley & Sons, Chichester, West Sussex, England ; Hoboken, NJ, 2004.

[49] Konstantin Lenz, Thorsten Lenck, and Frank Peter. The Liberalisation of Electricity Markets in Germany. 2019.

[50] Directive 96/92/ec of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity.

[51] Guido Pepermans. European energy market liberalization: experiences and challenges. *International Journal of Economic Policy Studies*, 13(1), January 2019.

[52] Hannes Weigt. A Review of Liberalization and Modeling of Electricity Markets. MPRA Paper 65651, University Library of Munich, Germany, October 2009.

[53] Andreas Jahn and Raffaele Piria. Überblick über die US-Strommärkte. 2017.

[54] William Hogan. Strengths and weaknesses of the PJM market model. *Prepared for the Handbook on the Economics of Electricity, Chapter 7*, pages 188–189, 2019.

[55] Karsten Neuhoff, Benjamin Hobbs, and David Newbery. Congestion management in European power networks: Criteria to assess the available options, October 2011. DIW Berlin Discussion Paper 1161.

[56] Ignacio Herrero Gallego, Pablo Rodilla Rodriguez, and Carlos Batlle Lopez. *Market mechanisms and pricing rules to enhance low-carbon electricity markets efficiency*. Madrid, 2018.

[57] ENTSO-E. First edition of the bidding zone review – Draft version for public consultation until 5 March 2018. 2018.

[58] Denis vom Stein, Hao Chang, Albert Moser, Carsten Pflanz, Benedikt Bartosch, Christoph Neumann, and Friedrich Kunz. The impact of German HVDC lines on the European electricity market. Retrieved December 23, from `https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/English/2020-01_EW_Beitrag_HVDC_Lines_final_englisch.pdf`, 2020.

[59] Barbara Burstedde. From nodal to zonal pricing: A bottom-up approach to the second-best. In *2012 9th International Conference on the European Energy Market*, pages 1–8. IEEE, 2012.

[60] Lukas Schmidt and Jonas Zinke. One price fits all? Wind power expansion under uniform and nodal pricing in Germany. Technical report, EWI Working Paper, 2020.

[61] Lalit Goel, Qiuwei Wu, and Peng Wang. Nodal price volatility reduction and reliability enhancement of restructured power systems considering demand–price elasticity. *Electric Power Systems Research*, 78(10):1655–1663, 2008.

[62] Scott M Harvey and William W Hogan. Nodal and zonal congestion management and the exercise of market power. *Harvard University*, page 21, 2000.

[63] EPEX SPOT. 15-minute intraday call auction: 3 pm – the new meeting point for the German market.

[64] Lion Hirth, Ingmar Schlecht, Christoph Maurer, and Bernd Tersteegen. Future redispatch procurement in Germany: Conclusions from the project Beschaffung von Redispatch, 2019.

[65] NEMO Committee. Euphemia public description: Single price coupling algorithm, 2019.

[66] Peter Cramton. Electricity market design: the good, the bad, and the ugly. In *Proceedings of the 36th Annual Hawaii International Conference on System Sciences.*, page 8. IEEE, 2003.

[67] Robert Wilson. Architecture of power markets. *Econometrica*, 70(4):1299–1340, 2002.

[68] Mehdi Madani, Carlos Ruiz, Sauleh Siddiqui, and Mathieu van Vyve. Convex Hull, IP and European electricity pricing in a European power exchanges setting with efficient computation of convex hull prices, 30.03.2018.

[69] Wedad Elmaghraby and Shmuel S. Oren. The efficiency of multi-unit electricity auctions. *The Energy Journal*, 20(4), 1999.

[70] Ramteen Sioshansi, Shmuel Oren, and Richard O'Neill. Three-part auctions versus self-commitment in day-ahead electricity markets. *Utilities Policy*, 18(4):165–173, 2010.

[71] Jörn C. Richstein, Casimir Lorenz, and Karsten Neuhoff. An auction story: How simple bids struggle with uncertainty. *Energy Economics*, 89:104784, 2020.

[72] Yanchao Liu, Jesse T. Holzer, and Michael C. Ferris. Extending the bidding format to promote demand response. *Energy Policy*, 86:82–92, 2015.

[73] Stig Ødegaard Ottesen and Asgeir Tomasgard. A stochastic model for scheduling energy flexibility in buildings. *Energy*, 88:364–376, 2015.

[74] Stig Ødegaard Ottesen, Asgeir Tomasgard, and Stein-Erik Fleten. Prosumer bidding and scheduling in electricity markets. *Energy*, 94:828–843, 2016.

[75] Diego A. Tejada-Arango, Afzal S. Siddiqui, Sonja Wogrin, and Efraim Centeno. A review of energy storage system legislation in the US and the European Union. *Current Sustainable/Renewable Energy Reports*, 6(1):22–28, 2019.

[76] United States Federal Energy Regulatory Commission. Electric storage participation in markets operated by regional transmission organizations and independent system operators, 2018.

[77] XBID Cross-Border Intraday Market Project. Cross-border intraday (xbid) trading solution pre-launch event, 2018.

[78] Gilbert Fridgen, Anne Michaelis, Maximilian Rinck, Michael Schöpf, and Martin Weibelzahl. The search for the perfect match: Aligning power-trading products to the energy transition. *Energy Policy*, 144:111523, 2020.

[79] Sushil Bikhchandani and Joseph M. Ostroy. The package assignment model. *Journal of Economic Theory*, 107(2):377–406, 2002.

[80] Leonardo Meeus, Karolien Verhaegen, and Ronnie Belmans. Block order restrictions in combinatorial electric energy auctions. *European Journal of Operational Research*, 196(3):1202–1206, 2009.

[81] Frank A. Wolak. Measuring the benefits of greater spatial granularity in short-term pricing in wholesale electricity markets. *American Economic Review*, 101(3):247–52, 2011.

[82] Jay Zarnikau, Chi-Keung Woo, and Ross Baldick. Did the introduction of a nodal market structure impact wholesale electricity prices in the texas (ercot) market? *Journal of Regulatory Economics*, 45(2):194–208, 2014.

[83] Karsten Neuhoff, Julian Barquin, Janusz W. Bialek, Rodney Boyd, Chris J. Dent, Francisco Echavarren, Thilo Grau, Christian von Hirschhausen, Benjamin F. Hobbs, Friedrich Kunz, Christian Nabe, Georgios Papaefthymiou, Christoph Weber, and Hannes Weigt. Renewable electric energy integration: Quantifying the value of design of markets for international transmission capacity. *Energy Economics*, 40:760 – 772, 2013.

[84] Anthony Papavasiliou, Alex D. Papalexopoulos, and Shmuel Oren. Market design for a decarbonized electricity market, 2017.

[85] Joachim Bertsch, Tom Brown, Simeon Hagspiel, and Lisa Just. The relevance of grid expansion under zonal markets. *The Energy Journal*, 38(5), 2017.

[86] Joachim Bertsch, Simeon Hagspiel, and Lisa Just. Congestion management in power systems. *Journal of Regulatory Economics*, 50(3):290–327, Dec 2016.

[87] David P. Brown, Jay Zarnikau, and Chi-Keung Woo. Does locational marginal pricing impact generation investment location decisions? an analysis of texas's wholesale electricity market. *Journal of Regulatory Economics*, 58(2):99–140, 2020.

[88] Christoph Maurer, Christian Zimmer, and Lion Hirth. Nodale und zonale Strompreissysteme im Vergleich. Technical report, Bericht für das Bundesministerium für Wirtschaft und Energie, 2018.

[89] Jörn Richstein, Karsten Neuhoff, and Nils May. Europe's power system in transition: How to couple zonal and locational pricing systems? Technical report, DIW Berlin, 2018.

[90] Christoph Fraunholz, Dirk Hladik, Dogan Keles, Dominik Möst, and Wolf Fichtner. On the long-term efficiency of market splitting in germany. *Energy Policy*, 149:111833, 2021.

[91] Veronika Grimm, Alexander Martin, Martin Weibelzahl, and Gregor Zöttl. On the long run effects of market splitting: Why more price zones might decrease welfare. *Energy Policy*, 94:453 – 467, 2016.

[92] David Schönheit, Constantin Dierstein, and Dominik Möst. Do minimum trading capacities for the cross-zonal exchange of electricity lead to welfare losses? *Energy Policy*, page 112030, 2020.

[93] Endre Bjørndal, Mette Bjørndal, Hong Cai, and Evangelos Panos. Hybrid pricing in a coupled european power market with more wind power. *European Journal of Operational Research*, 264(3):919 – 931, 2018.

[94] Karsten Neuhoff and Rodney Boyd. International experiences of nodal pricing implementation. *Working Document (Version July). Berlin: Climate Policy Initiative*, 2011.

[95] Nils G. May, Karsten Neuhoff, and Jörn C. Richstein. Europe's power system in transition: What are the evolving roles of future markets and hedging? Report based on the Future Power Market Workshop, 2019. http://hdl.handle.net/10419/204599.

[96] European Stakeholder Committee. Euphemia performance, 2015. https://eepublicdownloads.entsoe.eu/clean-documents/Network%20codes%20documents/Implementation/stakeholder_committees/EuphemiaPerformance_ESC_29%20SEP%202015_VF.PDF.

[97] Feng Zhao, Eugene Litvinov, and Tongxin Zheng. A marginal equivalent decomposition method and its application to multi-area optimal power flow problems. *IEEE Transactions on Power Systems*, 29(1):53–61, 2014.

[98] Lorenzo Kristov. Modernizing transmission-distribution interface coordination for a high-der future, 2017. https://www.energy.gov/sites/prod/files/2017/04/f34/2_T-D%20Interface%20Panel%20-%20Lorenzo%20Kristov%2C%20CAISO.pdf.

[99] Karsten Neuhoff, Jörn C. Richstein, and Carlotta Piantieri. TSO-DSO-PX Cooperation II. Report on key elements of debate from a workshop of the Future Power Market Platform, 2018. http://hdl.handle.net/10419/180382.

[100] Paul R. Gribik, William W. Hogan, Susan L. Pope, et al. Market-clearing electricity prices and energy uplift. *Cambridge, MA*, 2007.

[101] Richard P. O'Neill, Paul M. Sotkiewicz, Benjamin F. Hobbs, Michael H. Rothkopf, and William R. Stewart Jr. Efficient market-clearing prices in markets with nonconvexities. *European journal of operational research*, 164(1):269–285, 2005.

[102] George Liberopoulos and Panagiotis Andrianesis. Critical review of pricing schemes in markets with non-convex costs. *Operations Research*, 64(1):17–31, 2016.

[103] MISO. Informational compliance filing of the midcontinent independent system operator, inc. ferc docket no. er12-668-000, regarding extended locational marginal pricing.

[104] MISO. ELMP III White Paper I R&D report and Design Recommendation on Short-Term Enhancements.

[105] Justin Dijk and Bert Willems. The effect of counter-trading on competition in electricity markets. *Energy Policy*, 39(3):1764–1773, 2011.

[106] Mette Bjørndal, Kurt Jörnsten, and Virginie Pignon. Congestion management in the Nordic power market – counter purchases and zonal pricing. *Journal of Network Industries*, 4:273–296, 2003.

[107] Scott M. Harvey and William W. Hogan. Nodal and zonal congestion management and the exercise of market power, January 2000. Working paper, https://scholar.harvard.edu/whogan/files/zonal_jan10.pdf.

[108] William W. Hogan. Transmission congestion: the nodal-zonal debate revisited, February 1999. Working paper, https://scholar.harvard.edu/whogan/files/nezn0227.pdf.

[109] Pär Holmberg and Ewa Lazarczyk. Comparison of congestion management techniques: Nodal, zonal and discriminatory pricing. *Energy Journal*, 36(2):145–166, 2015.

[110] Veronika Grimm, Alexander Martin, Martin Schmidt, Martin Weibelzahl, and Gregor Zöttl. Transmission and generation investment in electricity markets: The effects of market splitting and network fee regimes. *European Journal of Operational Research*, 254(2):493–509, 2016.

[111] Francisco D. Munoz, Sonja Wogrin, Shmuel S. Oren, and Benjamin F. Hobbs. Economic inefficiencies of cost-based electricity market designs. *The Energy Journal*, 39(3), 2018.

[112] Martin Weibelzahl and Alexandra Märtz. Optimal storage and transmission investments in a bilevel electricity market model. *Annals of Operations Research*, pages 1–30, 2018.

[113] William W. Hogan. Getting the prices right in PJM: What the data teaches us. *The Electricity Journal*, 11:61–67, 1998.

[114] Peter Cramton and Axel Ockenfels. Ökonomik und Design von Kapazitätsmärkten im Stromsektor. *Energiewirtschaftliche Tagesfragen*, 61(9):14–15, 2011.

[115] Nils May, Karsten Neuhoff, and Jörn C. Richstein. Affordable electricity supply via contracts for difference for renewable energy. *DIW Weekly Report*, 28:251–259, 2018.

[116] Karsten Neuhoff, Nils May, and Jörn C. Richstein. Renewable Energy Policy in the Age of Falling Technology Costs. Discussion Papers of DIW Berlin 1746, DIW Berlin, German Institute for Economic Research, 2018.

[117] Paul Milgrom. Rational expectations, information acquisition, and competitive bidding. *Econometrica*, 49(4):921–943, 1981.

[118] Paul Milgrom and Robert Weber. A theory of auctions and competitive bidding. *Econometrica*, 50(5):1089–1122, 1982.

[119] Robert B. Wilson. Competitive bidding with disparate information. *Management Science*, 17(7):446–448, 1969.

[120] Richard Thaler. Anomalies: The winner's curse. *Journal of Economic Perspectives*, 2(1):191–202, 1988.

[121] Karsten Neuhoff, Nils May, Jörn Richstein, Mario Ragwitz, Marian Klobasa, and Silvana Tiedemann. Von der einseitigen zur symmetrischen gleitenden Marktprämie, 2018. http://hdl.handle.net/10419/175752.

[122] Department of Business, Energy and Industrial Strategy, UK. Contracts for difference for low carbon electricity generation. consultation on proposed amendments to the scheme, March 2020. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/885248/cfd-ar4-proposed-amendments-consultation.pdf.

[123] Thobias Sach, Bastian Lotz, Jasper Geipel, Laszlo Szabó, Maria Bartek-Lesi, Bettina Dézsi, and Corinna Klessmann. Auctions for the support of renewable energy in Germany, 2019.

[124] Bundesnetzagentur. Ausschreibungen für EE- und KWK-Anlagen, 2019. https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Ausschreibungen/Ausschreibungen_node.html.

[125] Aline Robert and Frederic Simon. French wind energy 'in limbo' for more than a year, 2019. https://www.euractiv.com/section/energy/news/french-wind-energy-in-limbo-for-more-than-a-year/.

[126] Karl-Martin Ehrhart, Ann-Katrin Hanke, and Marion Ott. A small volume reduction that melts down the market: Auctions with endogenous rationing, 2020. ZEW Discussion Paper No. 20-014.

[127] Abba P. Lerner. The concept of monopoly and the measurement of monopoly power. *The Review of Economic Studies*, 1(2):157–175, 1934.

[128] Stephen A. Rhoades. The Herfindahl-Hirschman index. *Federal Reserve Bulletin*, pages 188–189, March 1993.

[129] Severin Borenstein, James B. Bushnell, and Frank A. Wolak. Measuring market inefficiencies in California's restructured wholesale electricity market. *The American Economic Review*, 92(5):1376–1405, December 2002.

[130] Marcel Boiteux. Peak-load pricing. *The Journal of Business*, 33(2):157–179, 1960.

[131] Ralph Turvey. Peak-load pricing. *Journal of Political Economy*, 76(1):101–113, 1968.

[132] Oliver E. Williamson. Peak-load pricing and optimal capacity under indivisibility constraints. *American Economic Review*, 56(4):810–827, 1966.

[133] Koichiro Ito and Mar Reguant. Sequential markets, market power, and arbitrage. *American Economic Review*, 106(7):1921–1957, 2016.

[134] Blaise Allaz and Jean-Luc Vila. Cournot competition, forward markets and efficiency. *Journal of Economic Theory*, 59:1–16, 1993.

[135] Richard Green. The electricity contract market in England and Wales. *The Journal of Industrial Economics*, 47(1):107–124, 1999.

[136] Akshaya Jha and Frank Wolak. Can forward commodity markets improve short-term market performance? Evidence from wholesale electricity, September 2019. Working paper, Program on Energy and Sustainable Development, Stanford University.

[137] Frank A. Wolak. Wholesale electricity market design, November 2019. Working paper, Program on Energy and Sustainable Development, Stanford University.

[138] Nikolas Wölfing. Forward trading and collusion in supply functions, 2019. ZEW Discussion Papers 19-003, Mannheim, `https://madoc.bib.uni-mannheim.de/50019/`.

[139] John Birge, Ali Hortaçsu, Ignacia Mercadal, and Michael Pavlin. Limits to arbitrage in electricity markets: A case study of MISO, 2017. MIT CEEPR WP 2017-003.

[140] European Commission. Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, 2017. `http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32017R2195`.

[141] Karl-Martin Ehrhart, Fabian Ocker, and Marion Ott. Analyse des neu eingeführten Regelarbeitsmarktes. *Energiewirtschaftliche Tagesfragen*, 3/2021, forthcoming.

[142] Shmuel Oren, Pablo T. Spiller, Pravin Varaiya, and Felix Wu. Nodal prices and transmission rights: a critical appraisal. *The Electricity Journal*, 8(3):24–35, 1995.

[143] California ISO. Market power in the San Diego basin, 1999. Addendum to Annual Report on Market Issues and Performance.

[144] Severin Borenstein, James Bushnell, and Steven Stoft. The competitive effects of transmission capacity in a deregulated electricity industry. *The RAND Journal of Economics*, 31(2):294–325, 2000.

[145] David. B. Patton, Pallas LeeVanSchaick, Jie Chen, and Raghu Palavadi Naga. 2019 state of the market report for the New York ISO markets, 2020. Market Monitoring Unit for the New York ISO.

[146] Consentec, Fraunhofer ISI, Navigant, and Stiftung Umweltrecht. Untersuchung zur Beschaffung von Redispatch, 2019. Sammlung verschiedener Berichte und Kurzpapiere aus dem Vorhaben "Untersuchung zur Beschaffung von Redispatch" (Projekt 055/17) im Auftrag des BMWi.

[147] Lawrence Ausubel, Peter Cramton, Marek Pycia, Marzena Rostek, and Marek Weretka. Demand reduction and inefficiency in multi-unit auctions. *The Review of Economic Studies*, 81(4):1366–1400, 2014.

[148] Ziad Alaywan, Tong Wu, and Alex D. Papalexopoulos. Transitioning the California market from a zonal to a nodal framework: An operational perspective. *IEEE PES Power Systems Conference and Exposition*, 2:862–867, 2004.

[149] Christoph Graf, Federico Quagliay, and Frank A. Wolak. Simplified electricity market models with significant intermittent renewable capacity: Evidence from Italy, January 2020. Working paper.

[150] Mahir Sarfati, Mohammad Hesamzadeh, and Pär Holmberg. Production efficiency of nodal and zonal pricing in imperfectly competitive electricity markets. *Energy Strategy Reviews*, 24:193–206, 2019.

[151] Theo Geers. Beinahe-Blackout in Deutschland: Bundesnetzagentur rügt Stromhändler. Retrieved November 14, 2020, from https://www.deutschlandfunk.de/beinahe-blackout-in-deutschland-bundesnetzagentur-ruegt.1783.de.html?dram:article_id=475140, April 2020. Deutschlandfunk.

[152] Jean-Michel Glachant and Virginie Pignon. Nordic congestion's arrangement as a model for Europe? Physical constraints vs. economic incentives. *Utilities Policy*, 13:153–162, 2015.

[153] John List and David Lucking-Reiley. Demand reduction in multiunit auctions: Evidence from a sportscard field experiment. *The American Economic Review*, 90(4):961–972, 2000.

[154] Bundesnetzagentur. Hintergrundpapier: Ergebnisse der Ausschreibung für Windenergieanlagen an Land vom 1. Mai 2017, vom 1. August 2017, und vom 1. November 2017, 2017. https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Ausschreibungen/Hintergrundpapiere/Hintergrundpapier_OnShore_01_05_2017.pdf?_blob=publicationFile&v=3, https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Ausschreibungen/Hintergrundpapiere/Hintergrundpapier_OnShore_01_08_2017.pdf?_blob=publicationFile&v=4, https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Ausschreibungen/Hintergrundpapiere/Hintergrundpapier_OnShore_01_11_2017.html?nn=726056.

[155] Friedrich Kunz, Karsten Neuhoff, and Juan Rosellón. FTR allocations to ease transition to nodal pricing: An application to the German power system. *Energy Economics*, 60:176 – 185, 2016.

[156] Andreas Ehrenmann, Pierre Henneaux, Gerd Küpper, Johan Bruce, Björn Klasman, and Linda Schuhmacher. The future electricity intraday market design. Technical report, DG ENER, 2019.

[157] Kristin Dietrich, Uwe Hennemeier, Sebastian Hetzel, Till Jeske, Florian Leuthold, Ina Rumiantseva, Holger Rummel, Swen Sommer, Christer Sternberg, and Christian Vith. Nodal pricing in the German electricity sector–a welfare economics analysis, with particular reference to implementing offshore wind capacities. *Final report of the study project:'More Wind?'. Chair of Energy Economics and Public Sector Management at Dresden University of Technology. Working Paper WP-EM-08*, 2005.