D3.5 - Market design for a reliable ~100% renewable electricity system

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Ediion	**Date**	**Dissemina-tion Level**	**Description**
1.0	25.02.2020	Public	Report with a set of rules and regulations that fully describe a (near) completely decarbonized power market. These rules will be modeled in WP4 and WP5, including different options when there is no clear preference *ex ante*. The interim results of WP5 will be used to update the market design in this deliverable. Delivery month: 12, with subsequent updates in months 36 and 41 to reflect improved understanding as a result of the simulation model studies.
2.0	**25.07.2023**	**Public**	Revised report with a set of rules and regulations that fully describe a (near) completely decarbonized power market after all the public discussion and policy proposals arising from the energy crisis. The objective is to provide an overview of all high-level market design choices. A subset of these rules will be modeled in WP4 and WP5, focusing on the most promising choices, but including different options when there is no clear preference *ex ante*.

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Executive Summary

The goal of this report is to identify in which respects the design and regulation of electricity markets needs to be improved in order facilitate a (nearly) completely decarbonized electricity system. It provides a basis for scoping the modeling analyses that have already been or are to be performed in subsequent work packages in the TradeRES project. These simulations will provide the basis for an update of this deliverable in the form of a more precise description of an all-renewable electricity market design.

In this second iteration[1] of deliverable 3.5, we analyze how the current design of electricity markets may fall short of future needs. Where there is a lack of certainty about the best market design choices, we identify alternative choices. Alternatives may concern a choice between policy intervention and no intervention or different intervention options.

Section 2 outlines the current European electricity market design and the key pieces of European legislation that underlie it. The European target model is zonal pricing with bidding zones that are defined as geographic areas within the internal market without structural congestion. That implies that within one bidding zone electricity can be traded without considering grid constraints and there are uniform wholesale prices in each zone. The main European markets are Nordpool, EPEX and MIBEL. Trading between zones in the European Price Coupling Region occurs through an implicit auction where price and quantity are computed for every hour of the next day, using EUPHEMIA, a hybrid algorithm for flow-based market coupling that is considered the best practice in Europe at this time.

Within each bidding zone, electricity is traded via bilateral over-the-counter (OTC) contracts or on organized marketplaces (power exchanges) for different products with different time horizons. In the day-ahead market, traders buy and sell energy one day prior to delivery. An intraday market allows the adjustment of positions up to one hour before delivery time. Any remaining imbalances in the system after closure of the intraday market are settled in the balancing markets, which are operated by the transmission system operators (TSOs). Long-term products, i.e., (financial) futures and (physical) forwards, enable market participants to hedge long-term price risks.

TSOs and DSOs procure ancillary services such as for frequency control, voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability. Some countries have implemented capacity remuneration mechanisms, instruments for ensuring generation adequacy, but there is no agreement on the need for them, nor on the optimal design.

The Emission Trade System (ETS) for CO_2 emission rights sets a firm emission ceiling. Prices of emission rights have been volatile, but the EU's Backloading policy, the Market Stability Reserve and the faster reduction pathway that was agreed upon by the EU appear to have stabilized the price. However, the UK and the Netherlands have implement-

[1] This document will be updated once more in month 46, to reflect the development of the project's insights

ed a minimum price for CO_2 to provide additional security to investors in low-carbon technologies. In addition, European member states employ a variety of renewable energy support schemes.

Section 3 discusses the energy policy goals that guide electricity market design, taking the commonly expressed policy goals of a reliable, affordable and sustainable electricity system as a starting point. The way in which reliability is perceived may change in a system with a high degree of flexibility. Flexibility may reduce or even avoid outages due to shortages of generation capacity, but if shortages occur frequently, and electricity prices rise to high levels during these times, consumers may still not consider the objective of reliability to be met. Regarding sustainability, an all-renewable energy market, which is the objective of TradeRES, meets this objective implicitly. However, the project will also include analyses of scenarios with low but not zero emissions of CO_2. The most complex policy goal for an all-renewable energy system is the objective of welfare maximization (or economic efficiency). For markets to be optimal, their design and regulation must ensure incentive compatibility, meaning that all actors in the system have incentives to contribute with their behavior to the benefit of the system as a whole. Full incentive compatibility is not possible with respect to the integration of retail and wholesale markets and, especially, in the regulation of network tariffs and congestion management, so compromises need to be found that are socially acceptable and economically as efficient as possible. Other considerations in market design are price volatility and the associated risks to producers and consumers and revenue adequacy.

Section 4 describes the analytic framework for understanding electricity market design. The electricity system is decomposed into four physical dimensions: the geographic dimension (the coupling of European electricity markets), the system level (the links between DSOs and TSOs), the timescale dimension (the relations between the operational and investment timeframes) and the coupling with other energy vectors, mainly gas and heat. The market design and the regulation of network companies need to ensure the achievement of the policy objectives along all these dimensions.

Section 5 presents an overview of shortcomings of the current market design with respect to an all-renewable future system. Points of improvement for wholesale market design are:

- The lead times between market closure and delivery time are long due to the limitations on the forecast accuracy of the vRES;
- There may be insufficient arbitrage opportunities over a rolling time horizon of several days;
- The priority grid access that is provided to renewable energy can cause inefficiencies;
- There is a lack of incentive compatibility regarding the different types of flexibility, both on the supply and the demand sides.

Regarding retail markets, the current market design does not provide adequate incentives for the integration of retail and wholesale markets. Generation and flexibility resources at the retail level are often not even exposed to dynamic prices. In addition, distribution grid congestion management is just beginning to be implemented; current methods are far from optimal.

With respect to ancillary services, current markets are focused on procuring them from thermal generators. As variable renewable energy (vRES) sources develop into a mainstay of the energy system, it needs to participate fully in ancillary services markets, both on the side of paying for imbalances and on the side of being allowed to provide ancillary services. The participation requirements for ancillary services markets need to be adjusted in order to facilitate the participation of vRES, of distributed energy sources and of batteries and other energy storage facilities.

The development of many new types of flexibility will contribute to reliability and system adequacy. However, it is uncertain whether an energy-only market design will provide an optimal mix of investment in variable and controllable generation, energy storage and demand response:

- There is substantial regulatory and technology risk during the energy transition;
- vRES create price volatility and depress prices, reducing the business case for more investment in them;
- vRES create investment risk for controllable generation capacity, energy storage and demand response as well;
- Markets may develop an investment cycle;
- Legacy plants may distort the investment incentive for cleaner, innovative technologies during the coming decades.

In TradeRES, it is assumed that the current principle of zonal pricing will be maintained in the future in Europe, although the price zones may need to be made smaller. However, several factors limit the efficiency of cross-border electricity system integration in current markets:

- Different congestion management methods are applied within and between price zones; the congestion management methods have significant inefficiencies in themselves and in combination with each other;
- Internal congestion may limit cross-border network capacity;
- The network planning process does not depart from an EU-wide welfare maximization goal but is organized in a bottom-up manner;
- Technical network operating standards can be improved to allow a higher degree of utilization;
- The design of capacity markets is focused on single countries and does not consider trade in capacity products or the ability to rely on neighboring countries during periods of scarcity;
- The design of renewable support schemes is focused on single countries and does not consider trade and the opportunity to optimize the renewable energy portfolio on a continental scale;
- Intra-day and balancing markets are not harmonized and, therefore, hardly coupled across borders.

Sector coupling is expected to increase the flexibility of the energy system and in that way support the integration of vRES. The term is used in two ways: to indicate the electrification of demand sectors such as industrial processes, transport and space heating, and in reference to the closer integration between electricity and (an)other energy carrier. For sector coupling to be efficient, the market incentives for the coupled sectors need to be aligned. This does not only involve well-functioning and incentive compatible commodity pricing, but also alignment of taxes and levies and of the incentives provided by network tariffs.

The CO_2 Emission Trade System is expected to remain in place, but may need to be supported by a minimum price for CO_2. Renewable support schemes need to be harmonized and designed to achieve cost minimization across Europe, while ensuring renewable energy systems (RES) deployment targets and security of supply.

Section 5 ends with an analysis of the 2022 energy crisis and its impact on the discussion about energy market design in Europe. The crisis caused a shift away from reliance on market mechanisms in the public opinion as well as in the political and scientific discourses, leading to a stronger emphasis on security of supply and less emphasis on economic efficiency than before the crisis.

Section 6 summarizes the findings of the public consultation on electricity market design organized by the European Commission in early 2023. These findings have a direct bearing on the market design choices and their assessment and constitute one of the major contributions comparing with the first edition of this deliverable submitted in M12.

Section 7, finally, presents an overview of the market design choices that are suggested by the TradeRES project. The core recommendations are to combine liquid short-term markets with real-time pricing for everyone for whom benefits outweigh costs, including household consumers, with a decentralized capacity remuneration mechanism to ensure system adequacy of supply and to give consumers agency as well as price protection. The suggested solution requires consumers to purchase option contracts with which they ensure a minimum of available energy at an affordable price; by letting consumers decide how much they contract (within limits), they have an incentive to become flexible or develop behind-the-meter flexibility solutions. Risk hedging options, such as fixed-price contracts, should continue to be available. For variable renewable energy sources, support instruments are deemed likely to continue to be necessary. In this case, contracts for differences remain the chosen instrument; if it turns out that support is not necessary, e.g., because of a strong market for power purchase agreements (PPAs), they will phase themselves out because competition will drive vRES developers to request as little support as possible. However, this is not certain and as long as support is needed, contracts for differences will appear as the most suitable option. The project also provides recommendations regarding short-term and ancillary services market design. The main market design choices are summarized in Section 8 and in Table 1 on the next page. Please note that this table presents an overview – at a relatively abstract level – of all identified market design choices; the models in the Work Package 4 will represent a subset of these choices that will be analyzed in detail within the scope of Work Package 5 activities.

Table 1: Market design choices

Market design components	Base case	Market design alternatives	Comments
Wholesale market	Current design of day-ahead, intra-day and balancing markets. Assumption of well-functioning markets by stakeholders, im-provements needed to fit the penetration of vRES and flexibility.	Shorter lead times between market closure and delivery time; The implementation of a rolling time-horizon market clearing process; Trade shorter time units, e.g. of 30, 15 or 5 minutes; Different intra-day market designs; The addition of high-resolution, near-term forward markets as a product to power exchanges in order to facilitate time arbi-trage by vRES, storage units and flexible demand; Other options may be consid-ered as well, e.g. in order to facilitate new roles such as aggregators.	Various market designs may be considered. Opportunities for market power are an important aspect of short-term market design, but difficult to model. (E.g. game theoretic models or agent-based models with machine learning algorithms.)
Transmission networks	Redispatching within price zones, flow-based market coupling or market splitting be-tween price zones	Existing congestion manage-ment methods will be com-pared with locational marginal pricing; A case study of the benefit of dynamic line rating with re-spect to reducing network congestion will be performed. Design and study of the possi-bilities of auctioning and how transmission rights.	The issue of transmission network congestion management is not particular to a renewable electricity market, so the development of bet-ter methods for handling it is not an objective for TradeRES. However, because network congestion is an obstacle to vRES integration, transmission congestion and exist-ing congestion management meth-ods will be included in the analyses. Future design might take into con-sideration the possibility to auction transmission rights between market zones for periods longer than the year. This might help to boost the possibility of signing PPAs between countries.

Market design components	Base case	Market design alternatives	Comments
Retail market design	Fixed rates for small consumers, real-time pricing for large consumers.	Real-time pricing to be implemented in the entire market, also for small consumers and prosumers; To design a prosumer 'interface' and incentive structure. Opportunities for hedging in the long term for consumers such as mandatory offers at a fixed price for small consumers and standardization and larger liquidity of PPAs to ensure that larger consumers can access to them. Hybrid contracts with some band at fixed prices and other band exposed to real time pricing.	Research question: how to create a level playing field between retail and wholesale markets for vRES in case some of these are subsidized? Research question: how should prosumers interact with the energy system? Research question: how to design electricity tariffs that facilitate an efficient consumption of electricity while hedging consumers.
Distribution networks	Volumetric network tariffs for small consumers, mixed volumetric and capacity tariffs for commercial consumers	A selection of existing or proposed methods for distribution network congestion management; Innovations to network tariffs, such as capacity tariffs that are a function of consumption peak. Opportunities to include hybrid tariffs with a subscribed band of capacity and a non-firm band of capacity. Facilitate sharing electricity produced by consumers among them.	Distribution network congestion is developing as a result of decentralized generation and flexibility energy consumption. A combination of congestion management and incentives from network tariffs is needed to maintain secure operation of distribution networks in a low-carbon system. As with transmission network congestion, the development of new congestion management methods is not an objective for TradeRES, but the existence of congestion along with existing and proposed methods for handling it will be included in the project.
Ancillary services	Current division into FCR, aFRR and mFRR; Week-ahead procurement of balancing capacity; Marginal pricing (pay-as-cleared) for balanc-	Smaller minimum bid sizes; Aggregation of resources; Asymmetrical bids; Passive balancing; Dynamic procurement of reserves; Introduction of flexible ramping products;	Ancillary markets need to be reformed to allow new resources such as vRES, storage and demand response to replace thermal plant. Furthermore, TSOs shall adapt their balance procurement to a more weather-driven generation.

Market design components	Base case	Market design alternatives	Comments
	ing energy; Minimum bid size of 1 MW; Symmetrical bids for up and down regulation required; No aggregation of resources allowed; No passive balancing allowed; No procurement of inertia by the TSO.	Introduction of fast frequency response; Procurement of inertia by TSOs. Facilitate the provision of Ancillary Services by technologies such as vRES and non-fossil flexibility services such as batteries and demand response.	
System adequacy	Energy-only market (no support for system adequacy nor for vRES)	One or more capacity mechanisms will be studied. Candidates are a capacity market and capacity subscription. A key criterion will be to what extent they achieve integration of all flexibility options. Tenders for large-scale vRES; implicit support for small-scale vRES by adding cost of tenders to retail price.	Research question: does government need intervene to maintain system adequacy? Market design question: how to value the contribution of storage to system adequacy? Should other support instruments also be considered?
Cross-border trade: energy	Day-ahead markets are coupled, but intra-day and balancing markets not. Network constraints are allocated through flow-based market coupling. Bidding zone configuration as of today	Intra-day and balancing markets are coupled across borders. Locational marginal pricing (LMP, nodal pricing); Capacity mechanism design choice: whether and how to allow resources from neighboring markets to provide capacity. Study of the possibilities of auctioning and how transmission rights.	Which intra-day and balancing market design are needed for efficient cross-border trade in a near 100% RES system? Research question: how to determine to what extent a country (or a price zone) can rely on imports for its system adequacy? Design of the critical parameters to auction transmission rights

Market design components	Base case	Market design alternatives	Comments
Sector coupling	Spot market for H_2, H_2 network tariffs	Design of short-term markets for electricity and hydrogen; Adjustment of network tariffs for electricity and hydrogen.	Research question: which design of markets and network regulation achieves optimal performance of the integrated system? Inclusion of H_2 in the mechanism to integrate non-fossil flexibility services?
CO_2 policy	The ETS in its current form	A minimum price for CO_2. In all-renewable scenarios: no CO_2 emissions allowed.	Study scenarios with different CO2 price levels and evolutions.
vRES support schemes	No support	CfD, feed-in-premiums, capacity premiums, PPAs. Mandatory CfDs or not, retroactive CfDs or not	Are support instruments needed for financing vRESs and if so, how should they be designed? Are PPAs sufficient to deliver the required investment in vRES? Modelling of different designs of CfDs Analysis of the system performance under different CfDs designs
Taxes and levies	Not considered	Included in the analysis	

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List of Abbreviations

AC	alternating current
ACER	agency for the cooperation of energy regulators
aFRR	automatic frequency restoration reserve
AGC	auto governor control
BESS	battery energy storage systems
BM	balancing market
CCS	carbon capture and sequestration
CEER	Council of European Energy Regulators
CfDs	Contracts for Differences
DAM	day-ahead market
DERs	distributed energy resources
DR	Demand response
DSO	distribution system operator
EBGL	Electricity Balancing Guideline
ENTSO-E	European Network of Transmission System Operators for Electricity
ESCo	Energy service company
ETS	Emission Trade System
FCR	frequency containment reserve
FCR	frequency containment reserve
FiT	feed-in tariff
HVDC	high-voltage direct current
ID	intra-day
IDM	intra-day market
JAO	Joint Allocation Office
LMP	locational marginal pricing
mFRR	manual frequency restoration reserve
MIBEL	Mercado Ibérico de Electricidade
MSR	Market Stability Reserve
NEMO	nominated electricity market operators
OTC	over the counter (contracts)
PJM	Regional transmission organization (US East Coast)
PPA	power purchasing agreement
PV	photo-voltaic (solar panels)
RES	Renewable energy systems
RR	Replacement reserves
RTP	real-time pricing

SADC	Single Day-ahead Market Coupling
SIDC	Single Intraday Coupling
ToU	Time of use
TSO	Transmission system operator
TTF	Title transfer facility
TYNDP	Ten-Year Network Development Plan
USEF	Universal Smart Energy Framework
vRES	Variable renewable energy systems
XBID	European Cross-Border Intraday

1. Introduction

The goal of this report is to identify in which respects the design and regulation of electricity markets needs to be improved in order facilitate a (nearly) completely decarbonized electricity system. It provides a basis for scoping the modeling analyses that are to be performed in the TradeRES project. This report identifies areas of market design that may require improvement and promising market design options are identified. In subsequent work packages (WP4 and WP5), the most relevant market design choices for an all-renewable energy system will be analyzed with simulation models. These simulations, in turn, will lead to an update of this deliverable in the form of a more precise description of an all-renewable electricity market design. In this second edition[2] of deliverable 3.5, building upon the development of the first edition that was submitted in M12 of the project (de Vries, et al., 2021), we analyze how the current design of electricity markets may fall short of future needs. Where there is a lack of certainty about the best market design choices, we identify alternative choices. Alternatives may concern a choice between policy intervention and no intervention or different intervention options.

In this report, the term *market design* will be used to refer to the organizational and legal structure of the electricity markets, including the organized power exchanges, future markets, markets for ancillary services such as balancing market, and capacity markets. The term *regulation* refers to the legal framework for the monopoly functions – in our case the networks and system operator – as well as to the legal instruments for mitigating external effects, such as controlling emissions and supporting renewable energy. The two terms overlap to a degree; for instance, CO_2 emissions are regulated in Europe through the creation of a CO_2 market and some renewable support schemes rely on competition. Market design may be considered as a special case of regulation, to the extent that the rules are set by the government. However, the European power exchanges have considerable freedom to establish their own rules. When we use the term policy or policy intervention, this refers to legal changes in the market design or regulation.

To introduce the topic, Section 2 provides a brief overview of current European electricity markets, ending with a summary of the changes that the Clean Energy Package is bringing about. Section 3 describes how the way in which the policy goals for the electricity sector are achieved may change in the future. In Section 4, an analytic framework is presented to help structure market design questions, in which the dimensions of the electricity system that need to be considered when designing markets are described, as well as the relationship between the actors, whose actions are incentivized and constrained by the market design, and the physical system. In Section 5, an analysis is presented of how current market design may fail in an all-renewable system. We start this analysis with the expected changes to the physical supply chain for electricity and then review where these may conflict with its organization and regulation (governance). Section 6 presents an

[2] This document will be updated to reflect the project final developments.

overview of the identified market design choices. The project proposal committed to one set of market design rules; however, where there is uncertainty about the need for regulatory intervention, we analyze a market design with minimal regulation as well as one or more options for government intervention. A key example of such a case is long-term system adequacy, which can either be left to the market or ensured through a capacity mechanism. Given uncertainty about the best option, in this report we analyze a range of policy choices. Section 7 summarizes the identified market design choices which will serve as input for the model design in Work Packages 4 and 5.

2. Current European electricity market design

The European internal market for electricity is considered an important means to achieving Europe's target to become climate-neutral in 2050 as it allows to exploit the differences in generation profiles of renewable energy across Europe and therefore, improve security of supply and cost-efficiency (European Commission, 2020). Since 1996 the European Union is working on integrating national electricity markets to an internal market for electricity. The four European Energy Packages adopted in 1996, 2003, 2009 and 2019 lay the groundwork for an internal European electricity market by gradually establishing common market rules. While the first and second Energy package focused on liberalizing national markets, i.e. unbundling vertically integrated utilities and opening markets for competition, the third European Energy Package adopted in 2009 led to important regulations promoting European integration, i.e. the foundation of the Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E) (Pepermans, 2019). Amongst others, these institutions were instructed to develop Network Codes and Guidelines that constitute a set of detailed rules, such as standards for the allocations of cross-border transmission capacities, technical requirements for grid users or rules for coordinated grid operation, enabling coupling of national markets. Some of these rules were enshrined into law with the adoption of the fourth Energy Package. Their final aim is to establish the so-called European target model – a vision of the internal market for European electricity. The most relevant Regulations and Directives for European electricity market design are

- Regulation (EC) 2019/942 establishing the Agency for the Cooperation of Energy Regulators (ACER)
- Regulation(EU) 2019/943 on the internal market for electricity
- Directive (EU) 2019/944 on common rules for the internal market for electricity and amending Directive 2012/27/EU
- Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources

These are complemented by the following Guidelines developed by ENTSO-E and with the same legal implications as European regulations: (i) the capacity allocation & congestion management Guideline (CACM-GL), (ii) the Electricity Balancing Guideline (ElB-GL) and (iii) the forward capacity allocation Guideline.

The European target model aims at establishing a European electricity market with zonal pricing. In particular, the European market is split into bidding zones that are defined as geographic areas within the internal market without structural congestion. That implies that within one bidding zone electricity can be traded without considering grid constraints and there are uniform wholesale prices in each zone. If temporary grid constraints occur within one bidding zone, TSOs take appropriate measures, such as grid topology changes or redispatch, to enable the market outcome. In most bidding zones in Europe, there is one TSO responsible for maintaining the area's operational security and security of supply, i.e. providing and managing the electricity grid and keeping the system balanced at any point in time. Only in Germany the bidding zone is split into four so-called control areas managed by four different TSOs. Apart from Italy, Sweden and Norway, bidding zones are defined by national geographic borders.

Within each bidding zone, electricity is traded via bilateral over-the-counter (OTC) contracts or on organized marketplaces (power exchanges) for different products with different time horizons. In the day-ahead market traders buy and sell energy one day prior to delivery. Since each trader is balance responsible or must delegate this responsibility to a third party, the intraday market that closes at most one hour prior to delivery allows the adjustment of positions. If there are still imbalances in the system after closure of the intraday market, TSOs activate balancing products procured in balancing energy and capacity markets. Furthermore, long-term products, i.e. (financial) futures and (physical) forwards, enable market participants to hedge long-term price risks. In most European markets, dispatch is organized in a decentralized manner, i.e. generation schedules and consumption schedules as well as dispatching are determined by the scheduling agents of those facilities. Central dispatch conducted by the TSO is only carried out in balancing markets in Italy, Greece and Poland (Schittekatte et al., 2020).

2.1 Wholesale market design

Day-ahead markets (DAMs) are the most used and liquid physical markets. The main European markets are Nordpool, EPEX and MIBEL. These markets close at 12:00 PM (CET), 12-36 hours before physical delivery in central Europe, or 13-37 hours in Great Britain, Ireland and Portugal. In the Eastern European Time Zone, the time between market clearing and delivery is one hour shorter than in CET. The trading occurs through an implicit auction where price and quantity are computed for every hour of the next day, using EUPHEMIA, a hybrid algorithm that is used in the European Price Coupling Region. EUPHEMIA considers the system marginal pricing theory. It may consider simple and complex bids from both supply and demand sides, and may also take into account the physical constraints of the cross-zonal capacity. By computing the price and quantity for each bidding zone, the algorithm also defines the day-ahead flows between bidding zones.

Intraday markets (IDMs) may involve auctions, like DAMs, but with operation in that case taking place either in several sessions or continuously, using the pay-as-bid scheme or even using bilateral contracts. Transmission system operators (TSOs) consider the market results of DAMs, IDMs and bilateral contracts for scheduling the real-time operation. Deviations from schedules have to be balanced using the balancing mechanisms of the ancillary services markets, and the players that deviate, as balance responsible parties, need to pay (or receive) the imbalance prices. Prices resulting in DAMs serve as basis for (financial) futures and (physical) forward contracts that are traded bilaterally over-the-counter or on power exchanges and enable selling and buying electricity up to several years before delivery.

2.2 Retail market design

The liberalization of the retail market allows consumers to select their desired electrical energy provider and tariff, while before they were subject to regulated tariffs provided by a monopolist company (Algarvio et al., 2017). In retail markets, retail competition is performed by retailers proposing multi-part tariffs to consumers. The tariffs are typically com-posed of a fixed term (contracted power) and a variable term (energy used), and normally are equal to all consumers inside their consumption segment. In relation to the variable term of the tariff, consumers can also choose between simple or multi-rate prices. Typically, in retail competition, retailers sign private bilateral contracts with end-use consumers, obtaining a private portfolio to manage. To satisfy the consumption needs of the consumers that compose their portfolio, they enter into wholesale competition, submitting bids to spot markets and signing bilateral contracts with producers or other supply-side players.

2.3 Ancillary services markets

TSOs and DSOs provide ancillary services such as for frequency control, voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability. Across Europe, there are different financing mechanisms for these services in place. While power plants are obliged to supply these services to their respective system operators for free in some countries, other countries apply market mechanisms for a part of these services. Remunerations are usually financed via grid tariffs (Schittekatte et al., 2020).

The balancing mechanism (BM) is market-based, yet organized in different ways in different countries. BMs are mandatory to the European Network of TSOs (ENTSO-E). Operationally, TSOs have the responsibility to ensure that the power reserve values for BMs are satisfied within their control zones, based on ENTSO-E requirements. In Europe, there are three main types of load-frequency control products that are supplied by balancing service providers. During real-time operation, primary or frequency containment reserve (FCR) is the first product to be activated in response to grid disturbances, critical events or imbalances between production and consumption that result in frequency oscillations. It must be activated up to 15 seconds and the disturbances have to be remediated within 30 seconds. In some European control zones, FCR is a mandatory and non-remunerated system service for all generators connected to the grid, who have technical capability for fast response. They need to reserve 5% of their nominal power to FCR. Secondary or automatically activated frequency restoration reserve (aFRR) is to be activated in 30 seconds and may be deployed for a maximum of 15 minutes. Its function is to replace FCR and thereby free up FCR capacity in case of disturbances that stress the FCR capacity. Tertiary or manually-activated FRR (mFRR) is required to be capable of being fully activated in 15 minutes and may be required to be active for hours, with the purpose of freeing up FCR and aFRR (Algarvio, Lopes, Couto, & Estanqueiro, 2019; Poplavskaya & De Vries, 2019).

If the supply of balancing services is not mandatory, balancing energy and capacity are procured by the TSO in markets that are also operated by the TSO. Balancing products and market rules differ across Europe. In the EU-28 (before Brexit), there were four different methodologies for procuring balancing energy from aFRR markets: (i) pay as bid (adopted by eight countries); (ii) marginal pricing (adopted by eight countries); (iii) regulated price (adopted by three countries); (iv) hybrid (adopted by five countries). There are seven different methodologies for procuring balancing energy from mFFR markets: (i) mandatory offers (adopted by four countries); (ii) mandatory provision (adopted by two countries); (iii) pre-contracted offers (adopted by four countries); (iv) pre-contracted offers and mandatory offers (only France); (v) pre-contracted and free offer (adopted by four countries); (vi) bilateral market (adopted by two countries); (vii) organised market (nine countries) (Algarvio, Lopes, Couto, Santana, et al., 2019).

2.4 Capacity mechanisms

Capacity mechanisms are policy instruments that are implemented to ensure sufficient generation capacity. Examples in Europe are strategic reserves and capacity markets. While the need for capacity mechanisms is not agreed upon, many European countries have one implemented (Bublitz et al., 2018). A number of countries have capacity markets. In the UK, Ireland, Poland, Italy and Greece, the system operator purchases the capacity credits, while France has a decentralized design in which the retail companies are responsible for covering their peak load with capacity contracts. In a number of other countries, a strategic reserve is implemented. An overview of capacity mechanisms can be found in De Vries (2004a) and Cigré (2016), while Hoeschle (2018) provides an outlook toward their role in low-carbon energy systems. ACER and CEER describe the current status of capacity remuneration mechanisms in Europe (ACER and CEER, 2019).

2.5 Cross-border market integration

The Multi-Regional Coupling project has been created with the objective of coupling internal electricity markets on the basis of the Single Price Market Coupling for DAMs, with implicit allocation of cross-border capacities[3]. It also aims to ensure a harmonized approach to market organization and a more efficient use of cross-border transmission capacities. The coupled area is covering twenty-three European countries representing more than 85% of the European power system (Austria, Belgium, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Great Britain, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden). Market coupling mechanisms are founded on the reference prices that emerge from liquid markets (Algarvio, Lopes, Couto, Santana, et al., 2019).

Market coupling uses implicit auctions, where players trade energy on exchanges without any allocation of cross-border capacity, using EUPHEMIA, containing an algorithm based on the system marginal pricing theory (Sleisz et al., 2014). It may consider simple and complex bids from both the supply-side and the demand-side, and may also take into account physical constraints of the cross-zonal capacity. By obtaining the price and volume for each bidding zone, the algorithm also defines the day-ahead flows between bidding zones. Exchanges use the existing transmission capacity to minimize the price differences between two or more areas. Therefore, market coupling maximizes social welfare,

[3] https://www.entsoe.eu/network_codes/cacm/implementation/sdac/

avoiding potential errors in the splitting of markets, and sending relevant price signals for investment in more interconnection capacity. The efficiency of this mechanism is indicated by an increase in the price convergence between different market areas.

Long-term cross-zonal transmission capacity rights, which enable the cross-border exchange of forward contacts, are auctioned explicitly by TSOs at least for annual and monthly time frames, but the aim of proposed regulation is to extend these rights up to years. EU regulation established harmonized methods for the allocation and calculation of cross-border capacity. For the latter either the flow-based or net transfer capacity calculation method can be applied. Furthermore, it led to the creation of an allocation platform, the Joint Allocation Office (JAO), by 20 TSOs from 17 countries and its designation as the single European allocation platform for long-term cross-zonal transmission capacity rights.

While the coupling of national forward and day-ahead markets is already quite advanced, the intraday and balancing markets are still mostly national and coupling is in an earlier stage. For IDM, the Single Intraday Coupling (SIDC[4]) enables continuous cross-border trading in Europe by making use of a shared order book collecting orders of different nominated electricity market operators (NEMOs) and a capacity management module for managing the implicit or explicit capacity allocation. Yet it does not cover as much bidding zones as the Single Day-ahead Market Coupling (SADC) and not all ID products as well as no flow-based allocation. For reserve markets, some effort for coupling is made, too. For FCR, there is a cooperation between the TSOs for German, Belgian, Dutch, French, Swiss and Austrian Markets who procure FCR in common tenders[5]. For aFRR, the International Grid Control Cooperation forms an initiative for imbalance netting, covering 24 countries as of February 2021[6].

The legal basis for market coupling is given by the market guidelines that define methods for the calculation and allocation of cross-border capacities in the long (FCA-GL) and short term (CACM-GL) as well as standard balancing products and gate closure times (EB-GL).

2.6 Carbon market

The Emission Trade System (ETS) for CO_2 emission rights is the European Union's flagship environmental policy instrument. The fact that the system sets a firm emission ceiling ensures that the emissions targets are achieved. The ETS allocates available

[4] https://www.entsoe.eu/network_codes/cacm/implementation/sidc/u;
https://www.entsoe.eu/network_codes/cacm/implementation/sidc/;
https://www.entsoe.eu/network_codes/cacm/implementation/sdac/

[5] https://www.regelleistung.net/ext/static/prl

[6] https://www.entsoe.eu/network_codes/eb/imbalance-netting/u

emission rights to polluters with the highest willingness to pay, thereby ensuring short-term economic efficiency. However, past price volatility and the risk that the price of emission rights may drop to levels close to zero pose an obstacle to investment in decarbonization.

The transition to a low-carbon energy system is to a large extent an investment challenge, not only in renewable energy, but also in new energy networks and in flexibility options such as energy storage. In theory, the gradual reduction of the CO_2 emissions ceiling under the ETS should lead to a gradually increasing price for CO_2 emission rights. Observing this, investors would tend to shift towards increasingly low-carbon options in the course of the energy transition, until by 2050 the emission rate of the energy system would be close to zero.

However, in practice, the CO_2 price has been unstable. After the economic crisis of 2008, the CO_2 price dropped from more than 25 €/ton to as low as 5 €/ton in 2013. In 2018, the price exceeded 20€/ton again for the first time in years, but if the Corona crisis causes a sustained reduction of energy demand, the price may decline again. Low CO_2 prices may even occur in a scenario with higher growth of energy demand if there is more investment in decarbonization than anticipated.

This price uncertainty creates significant investment risk and therefore discourages investment in CO_2 reduction. An additional consideration is that a low CO_2 price indicates that the marginal cost of abatement is low; considering the difficulty that the world has to achieve its climate ambitions, this means that an opportunity to reduce CO_2 emissions at low cost is missed. Consumers face the opposite problem from investors in the energy sector. If CO_2 emission rights become scarce, e.g. because the economy grows faster than expected or the EU has set tight emission limits, then the resulting high price of CO_2 will be passed through to their energy bills.

The EU has recognized this issue and 'Backloaded' emission allowances during 2012-2019, i.e. they withheld emission allowances from the annual auctions. Eventually, the EU placed these allowances in a Market Stability Reserve, which will release the excess allowances only in case of a shortage of allowances. However, the criteria for adding and withdrawing allowances to and from the reserve are based on the volume of allowances in the market, so the effect on the allowance price is indirect and price risk is therefore not fully removed.

A more direct way to mitigate CO_2 allowance price risk is to implement a minimum price for CO_2. The UK and the Netherlands have done this (in different ways) and countries like France and Germany are also considering it. EU member states can implement a minimum price by creating a supplementary CO_2 tax that is equal to the minimum price for CO_2, e.g. 20 GBP in the UK, minus the market price for CO_2 emission allowance. A more elegant solution would be to implement it at the European level, in which case a reserve price at the annual auction for CO_2 credits would be the preferred solution.

2.7 Renewable Support Schemes

Generation from renewable energy sources as a relatively new technology is supported via different schemes in all member states of the European Union. Yet, volumes as well as support schemes differ. Weighted RES support per MWh varies from 12,87 €/MWh in Norway up to 198 €/MWh in the Czech Republic. Across Europe feed-in-tariffs, feed-in-premia, green certificates, Contracts for Differences (CfDs) as well as investment grants are applied as a support scheme – most of which are determined administratively, while some are tendered. All European countries apply technology-specific support schemes and almost all include all onshore renewable generation technologies, i.e., PV, wind on-shore, bioenergy and hydro. Exceptions are Ireland, which does not support PV. Cyprus only supports PV, while Malta supports onshore wind and PV. Offshore wind receives support schemes in Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Latvia, The Netherlands, Norway, Poland, Portugal, Sweden, and the UK. Technology-neutral schemes are starting to be implemented in some countries.

Besides explicit support schemes, renewable generation is supported by other measures across Europe. For instance, only renewable generation subject to a certain support scheme and above a certain size threshold is balance responsible in Denmark, Hungary, France, Germany, Italy, Latvia, Luxemburg, and Portugal. As far as grid connection is concerned, Denmark and Portugal apply a different connection tariff scheme to renewable generation in contrast to conventional generation technologies, while 13 countries guarantee priority grid connection for renewable generation and almost all Member States dispatch renewables with priority. Furthermore, particularly small-scale renewables installed by prosumers are indirectly supported via different forms of net metering, tax or levy exemptions, investment subsidies or other measures across Europe (Council of European Energy Regulators, 2018). First renewable generation projects are or will be realized without any support scheme, either relying on market revenues or Power Purchasing Agreements (PPAs).

2.8 Changes Induced by the Clean Energy Package

In 2019, the European Commission presented a new regulation of the Internal Market for Electricity, Regulation (EU) 2019/943. It includes legislation for a gate closure of spot markets closer to real-time operation, balance responsibility for RES, aggregated bidding, reduction of the market time unit up to 15 minutes (in 2025), implicit allocation of the cross-border capacity, participation of variable renewable energy in BMs, etcetera (Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the Internal Market for Electricity, 2019).

Regarding the balancing responsibility, Article 5 has four key paragraphs. The first paragraph defines that all market participants shall be financially responsible for imbalances, with only a few restrictions, specified in the second, third and fourth paragraphs that are related to demonstration projects for innovative technologies, generation facilities under 400 kW and installations benefiting from support under TFEU before 2019.

Balancing markets should be harmonized according to the rules of Article 6. In brief, the fourteen paragraphs of Article 6 indicate that all market participants shall have access to balancing markets ensuring an effective non-discrimination between participants. They also indicate the need to separate procurement between balancing energy and capacity, and between upward and downward balancing capacity, incentivizing the maximum use and efficient allocation of the cross-zonal capacity, considering the exclusive use of the marginal pricing methodology. Furthermore, the settlement of imbalance prices has to reflect the real-time price of electricity.

Article 7 presents rules to the day-ahead and intraday markets. Considering that the markets have to be organized in such a way as to be non-discriminatory, allowing all markets participants to access the market individually or through aggregation, they maximize the ability of market participants to contribute to avoid system imbalances. They also maximize the opportunities for market participants to participate in cross-border trade as close as possible to real time across all bidding zones and make no distinction between trades performed within a bidding zone and across bidding zones.

The rules for trading in the day-ahead and intraday markets are presented in Article 8, indicating that the market operators are free to develop new market products to increase the participation of the demand side, demand response, small-scale renewables and energy storage. By 1 January 2025, the imbalance settlement period shall be 15 minutes in all control areas and shall not exceed 30 minutes where an exemption has been granted by all regulatory authorities within a synchronous area, being all players allowed to perform trades in time intervals which are at least as short as the imbalance settlement period.

Concerning security of supply, Article 21 defines general principles for capacity mechanisms, while Art. 10 abolished minimum and maximum technical bidding limits to allow high scarcity rents for generators providing secure, dispatchable capacities. Furthermore, the Clean Energy Package addressed available cross-border capacities remaining below their potential due to internal congestion by enshrining the CACM-GL into law with Article 16 of the Regulation on the internal market for electricity. Particularly, more pressure was put on solving structural congestion within a bidding zone by introducing minimum interconnection capacities to be available by 2025 as well as regular bidding zone reviews (Article 14). Finally, new legal roles were created for new actors entering the market within the recast of Directive (EU) 2019/944 on common rules for the internal market for electricity as well. Particularly, its Articles 13, 15 and 16 legally established aggregators, active costumers and citizen energy communities, respectively.

3. Energy policy goals

Taking the commonly expressed policy goals of a reliable, affordable and sustainable electricity system as a starting point, the characteristics of a renewable electricity system require a reconsideration of the performance indicators for these goals (Directive 2019/944 on Common Rules for the Internal Market for Electricity, 2019). Deliverable 3.1 provides this analysis of the performance indicators and specifications for a renewable electricity system. Here, we summarize the main considerations regarding electricity sector policy goals to frame the discussion of market design and regulation in this report.

3.1 Security of supply

In the past, when electricity consumption was largely irresponsive to price, reliability was measured in a technical manner, i.e. by the average number of minutes of service interruption per customer (Brancucci Martínez-Anido et al., 2012). In a future, flexible system, however, some customers may choose to reduce or shift their consumption when the price is high. This prompts the question whether a power system with continuous service but average prices that are much higher than average cost due to frequent shortages is considered reliable or not. Price-elasticity of consumers adds an economic dimension to the concept of reliability. If there is sufficient price elasticity, a shortage of electricity generation capacity (and storage) does not lead to an energy imbalance and, in an extreme case, rolling blackouts, but it does mean that the price of electricity is high and part of demand is not served. In such cases, traditional reliability indicators that focus on service interruptions no longer suffice and a new indicator (or set of indicators) that includes the cost of service may need to be found. One possible indicator is the ratio between annual revenues and annual costs of energy supply companies: if they earn above-normal profits consistently, this could indicate structural scarcity. Deliverable 3.1 discusses this issue. The research insights were also published in L. de Vries & Sanchez Jimenez (2022).

In order to provide renewable electricity in a reliable manner, there needs to be sufficient investment both in vRES, which will provide the bulk of the energy, and in flexibility: facilities that ensure system adequacy at all times, such as hydrogen power plants, storage facilities and demand response. While a market should provide both in theory, there are concerns that even optimally designed markets may fail to provide sufficient incentives in practice, among others due to long-term weather variability, a risk of an investment cycle and, especially during the energy transition, policy uncertainty. System adequacy – as opposed to the conventional focus on generation adequacy – is therefore a key attention point for a renewable electricity supply system, and consists both of sufficient vRES and sufficient flexible resources.

vRES increases price volatility, but increased flexibility, e.g. from energy storage and demand response, reduce volatility; an open question is therefore how these countervailing trends balance out. In the longer term, weather variability may cause significant fluctuations in annual revenues of vRES and controllable generation alike, potentially increasing investment risk. The modeling analyses in TradeRES will need to indicate the system performance with respect to revenue adequacy, price volatility and risk as well, as is elaborated in D3.1 (Sanchez Jimenez et al., 2021). The optimization-based analysis of the techno-economic choices for a low-carbon electricity system that will be made in Work Package 2 will serve as a benchmark for evaluating the market design in the simulations in Work Package 5.

3.2 Sustainability

The sustainability of the system is crucial to achieve the decarbonization of the energy sector as a whole. Electricity produced by renewables can rapidly reduce the Green House Gas emissions and the electrification of other energy sectors will also contribute to the overall decarbonization of the economy. Different studies show that a 100% renewable energy system is feasible and cost effective. This future sustainable system will present a base of vRES and a set of non-fossil flexibility facilities to ensure the security of supply. In that sense, the penetration of vRES in power systems is already reducing to a large extent the share of emissions associated with the power sector. TradeRES studies electricity systems with ~100% renewables that combine vRES and flexible resources to achieve a sustainable power system.

With respect to the policy goal of sustainability, the goal of TradeRES is to investigate the design of an all-renewable electricity system, so this goal is translated into a requirement that only renewable energy sources are used (and net CO_2 emissions therefore are zero by definition). Within TradeRES, we may compare analyses that confirm with this goal with other low-carbon scenarios, for instance ones that include fossil fuel plants with CCS and nuclear power. In this case, the CO_2 emissions will become a key indicator.

3.3 Welfare maximization

The most complex policy goal for an all-renewable energy system is the objective of welfare maximization (or economic efficiency). The objective for market design and regulation is to induce the actors who operate the energy system together to make decisions that are optimal from a social perspective, i.e. from the perspective of the entire system, including external costs, in the short and in the long term. Given a certain reliability standard and environmental constraints such a (zero) CO_2 emissions standard, this means finding the least-cost solution that matches these requirements. According to neo-classic economic theory, markets will maximize social welfare if a number of conditions are met. For markets to be optimal, their design and regulation must ensure incentive compatibility, meaning that all actors in the system have incentives to contribute with their behavior to the benefit of the system as a whole. One important requirement for incentive compatibility is that external costs are internalized. In case of energy, the main external cost is climate change, but in an all-renewable energy system this cost is removed. A larger challenge looms in the setting of prices, both for energy and for network services.

Incentive compatibility means that all activities with the same cost or benefit to the system are priced the same way. This is not the case in current markets: if the electricity that is produced by rooftop solar installations is netted with household consumption, for instance, the solar energy receives a higher remuneration than commercial-scale wind parks that are producing at the same time for the wholesale market. More generally, retail consumers and prosumers face different prices from wholesale actors currently. Because retail electricity markets increasingly comprise electricity generation, storage and demand flexibility, integrating these markets with wholesale markets is a necessary step towards a renewable energy system. Similarly, further cross-border market integration will support the economically efficient integration of vRES in Europe. Therefore, one of the key challenges to market design is to achieve incentive compatibility within the entire energy system, as described in Section 4.

A key challenge to this objective is posed by the fact that energy networks tend to be regulated monopolies and that consequently, the incentives for the operation and expansion of energy networks, as well as the incentives to the users of the networks, are determined by regulation rather than by market forces. Vogelsang (2005) showed that incentive compatibility is not achievable because of inevitable tradeoffs between achieving cost recovery and providing efficient incentives to network operators and network users. In practice, considerations like feasibility, transparency and fairness create additional constraints to network regulation. In the past, when most network users were passive consumers, this mattered less, as the allocation of network costs was mainly an issue of fairness and cost recovery. With the advent of price-responsive prosumers and other forms of flexibility, network regulation has an increasing impact upon system performance. Well-known examples are distribution grid congestion caused by solar panels or by the simultaneous charging of electric vehicles. In many cases, expanding network capacity – the conventional solution to high demand – is not the socially optimal solution, curtailment of generation or load shifting can be achieved at (much) lower social cost. The question of network tariff design is complicated by the need to provide efficient incentives to alternative solutions such as energy storage, and by the fact that the same activity may create different costs at different times, such as solar PV injections that help flatten a demand peak at one moment and may create grid congestion at another time. Finally, from the consumer perspective, opportunity costs of demand flexibility at the retail level might not be incorporated in demand bids.

4. Analytic framework

4.1 Energy System dimensions

To structure the market design questions at hand, it is helpful to consider the energy system as consisting of a set of different dimensions among which market design goals need to be achieved. At the core of the analysis is system operation, i.e. the matching of supply, storage and demand within the constraints of the network, which needs to take place in a reliable and economically efficient manner. Figure 1 depicts four physical dimensions of the energy system that can be used to structure aspects of market design: the geographic dimension, the system level, the time scale and the connection to other energy vectors. This perspective is also useful when designing energy system models, as each dimension presents a choice with respect to model scope and detail.

The geographic dimension refers to the cross-border integration of European energy markets. While this has been an attention point since the liberalization of the markets in the 1990s, the energy transition has lifted the issue to higher prominence as long-distance system integration is a relatively low-cost way to integrate variable renewable energy. An important aspect is of course that the existing infrastructure should be used efficiently, which means that market integration continues to be relevant.

The second dimension is the system level, from distribution to transmission, and perhaps in the future to continental overlay networks, for electricity, natural gas and the new networks that will be required for hydrogen, and perhaps other molecular energy vectors and CO_2. As more generation and more flexibility options are developing at the local level, the integration of these resources into system balancing and network congestion management are increasingly requiring TSO-DSO cooperation.

The timescale dimension refers to the fact that one can no longer abstract from short-term system behavior in long-term planning. The business case for a new battery or wind park depends on short-term prices during its life span, so the investor needs to have a detailed understanding of the future energy system in which the asset is to function in order to make an investment decision. As a consequence, long-term (planning) decisions require insights in short-term (operational) system behavior. See also Section 1 of Deliverable 3.1.

The fourth dimension is the coupling of different energy vectors. Many decarbonization options lead to electrification, e.g. of transport, heat and industry. At the same time, hydrogen or another molecule-based energy vector will be necessary for storing and transporting energy. CO_2 networks may be needed to support decarbonization where electrification or fuel switching, e.g., with hydrogen, is not feasible and to deliver carbon dioxide removal from the atmosphere, e.g. through the application of CCS to bioenergy. While natural gas now only can be combusted, e.g. in a power plant, the development of electrolyzers means a two-way connection between electricity and gas. The link with heat networks is also relevant, because storing heat is a relatively cheap form of energy storage and therefore a potentially important source of system flexibility. Additionally, cogeneration of heat and electricity demonstrates the efficiency and cost benefits that sector integration can deliver. District heating and cooling networks offer a ready-made, proven solution for the decarbonization of the heating and cooling sector.

The energy transition requires a nearly complete rebuilding of Europe’s energy sector over the coming decades. The required investments are made by competitive companies, regulated network operators, consumers and other organizations such as energy cooperatives and energy communities. The degree to which these investments are coordinated depends on the market design and regulation of the system, as they determine the investment and dispatch incentives for the actors.

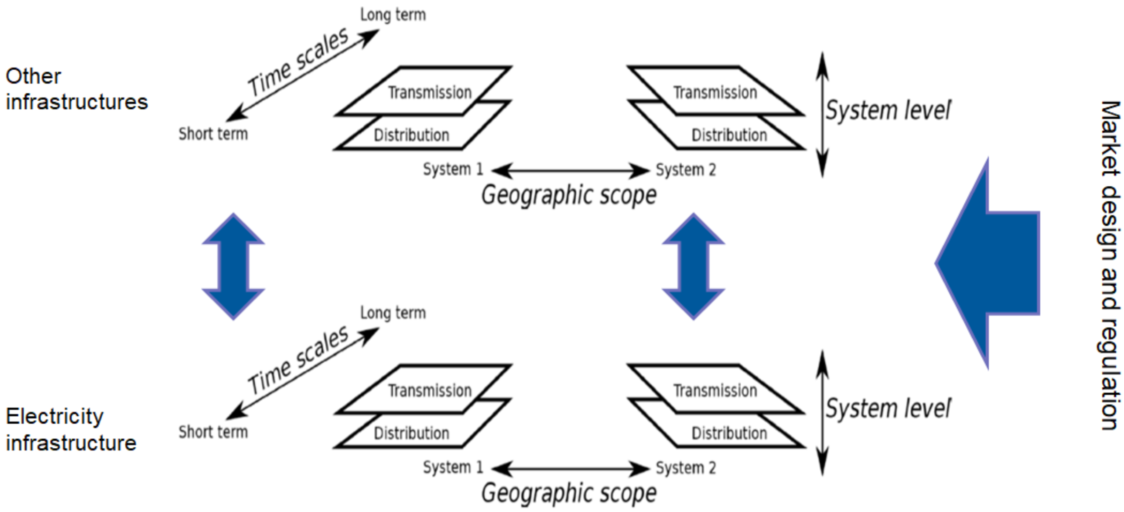

Figure 1: The four dimensions of the energy system: the geographic dimension, the system level, time scales and energy vector.

4.2 The relationships between the physical infrastructure and the actors

The market design and regulation of the energy sector together constitute the sector-specific set of rules and regulations that constrain and incentivize the actors in the system. The actors are also affected by the general legislative framework that is in place, but this is outside our scope and therefore we consider it as immutable. The challenge at the core of this research project is how to regulate and design electricity markets in such a way that they best achieve the policy goals, considering their role as part of an integrated energy system.

The regulation of the power sector needs to reflect its physical characteristics, as they determine the economic characteristics, the scope for competition and the cause of market failures. Therefore, it is useful to make a clear distinction, both in qualitative analysis and in computer modeling, between physical components and actors. Figure 2 shows how the main types of actors and physical components relate in a conventionally organized

European electricity system. At the bottom is a maximally simplified representation of the physical value chain. The dark blue octagons show the monopoly functions, the green rectangles represent market actors, the green circles the different wholesale markets and the red dots indicate the functions of a European TSO. There are different design options: e.g. in the USA, the system operator is often separate from the transmission network manager, while system operation is integrated with market operation into a power pool. In addition, in many countries there is no retail market, with the distribution network operator also providing retail services, i.e. purchasing power in the wholesale market and selling it to end consumers.

As European power systems are being decarbonized, their organization will need to adapt to the changing physical system. Variable renewable generation, storage, decentral generation, demand flexibility and system integration are the main trends that will require a rethinking of the market design of Figure 2.

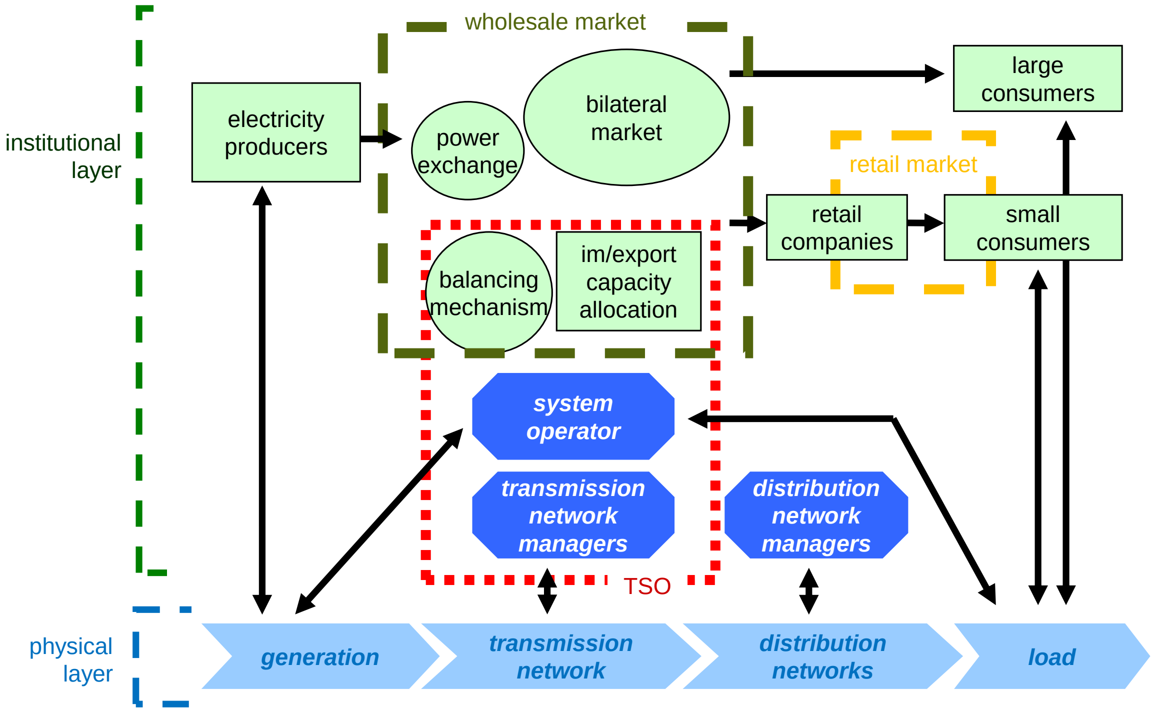

Figure 2: Decomposing an electricity system into the physical and institutional components.

5. Problem analysis: shortcomings of current electricity market design

This section reviews potential friction between the techno-economic characteristics of a low-carbon electricity system and current electricity market design in Europe. We structure our review of changes that are being brought about by the energy transition by first reviewing the core of the electricity market, namely the wholesale market, and to what extent it achieves economic efficiency in the short and the long term. Next, we proceed with the other three physical dimensions that were presented in Section 4.1, leading us to review cross-border market integration, the integration of transmission and distribution (and their associated wholesale and retail markets) and sector coupling.

5.1 Wholesale market design

In order to meet the policy goals of reliability and affordability, the objective for short-term market design is the efficient utilization of available resources to meet demand. Short-term market design no longer is a matter ensuring that generation resources meet demand in an efficient manner. A consequence of the energy transition is that the market now needs to provide an optimal combination of generation, storage and demand response at all times. The shift from thermal plants, some of which have long start-up times and slow ramp rates, to variable renewable energy and fast-response units like batteries, demand flexibility and modern gas plants, may enable a change in the organization and timing of the sequence of day-ahead, intra-day and balancing markets. The weather dependence of vRES may increase imbalances, but shorter market closure lead times would reduce this effect by taking advantage of more accurate power forecasts, thus reducing errors in the system. The reduced role of large, conventional power plants may reduce the need for long lead times (Algarvio, Couto, et al., 2019), which would facilitate vRES, but there may continue to be units with low ramp rates, both on the electricity generation and consumption sides of the market. Examples are gas plants (with hydrogen as a fuel), biomass plants, electrolyzers and other large industrial processes. Therefore, a compromise will need to be found between the need to accommodate facilities with ramping constraints, which need longer lead times, and variable renewable energy sources, for which a short time between market clearing and delivery reduces weather uncertainty.

In the simulation models in the TradeRES project, a wide range of technologies will be included in order to evaluate the impacts of short-term market design choices on the performance of energy systems with different technology mixes. The conversion of energy from electricity to hydrogen and back will be considered as an essential aspect of a future low-carbon electricity system, even if the focus of the project remains on the design and regulation of the electricity system. The flexibility of consumers (industrial and other) will be included in the scenarios as well.

As the variability of renewable energy will be offset at least partly by an increase in energy storage and demand flexibility, the way in which wholesale electricity prices are formed will change. In a low-carbon, high-vRES energy system, both supply and demand vary, whereas in a thermal power system, the volume of generation capacity is more or less fixed and generation follows load. To ensure that supply and demand are met in a high-vRES electricity system, new forms of flexibility are needed in both supply and demand. When vRES is in short supply, there will be hours when the price of electricity is not determined by the marginal cost of generation but by the marginal willingness to pay of consumers. Some consumers will choose not to purchase electricity when the price is too high (Figure 3). Their demand shifts to times of abundant vRES, as illustrated in Figure 4. Energy storage facilities play a similar role: they return electricity to the system when the price is high, which is during times of scarce vRES (Figure 3) and recharge when there is ample vRES, increasing the demand for electricity (Figure 4).

In current markets, the effect of filling energy storage units that is shown in Figure 4 is not yet apparent, as the volume of electricity storage facilities is low. As a result, at times of high vRES generation, other generators are pushed out of the market and the wholesale price becomes low or even negative (Strbac et al., 2021). In a market with sufficient storage capacity and demand response, such low prices should not be common. An increase in flexibility from storage and demand response also helps to dampen high peak prices, as is shown in Figure 3. Again, this effect is not strong yet in current markets. Instead of storage and demand response, fossil fuel power plants currently make up the shortfall when vRES output is low.

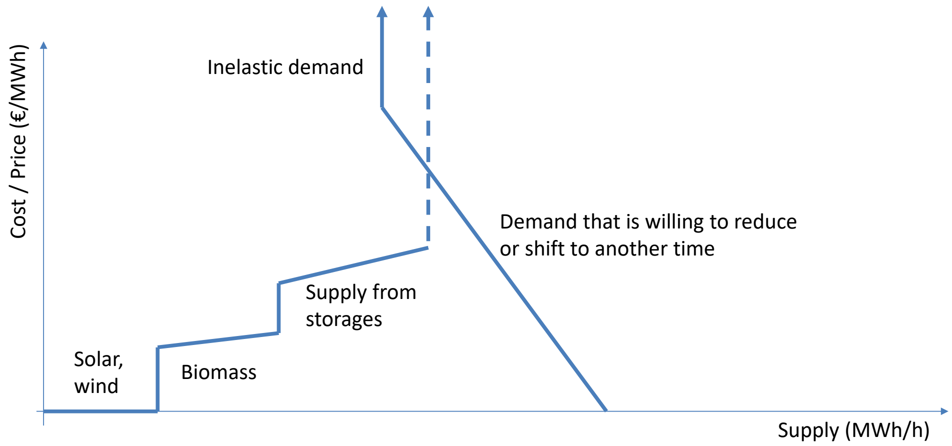

Figure 3: Price formation with limited vRES

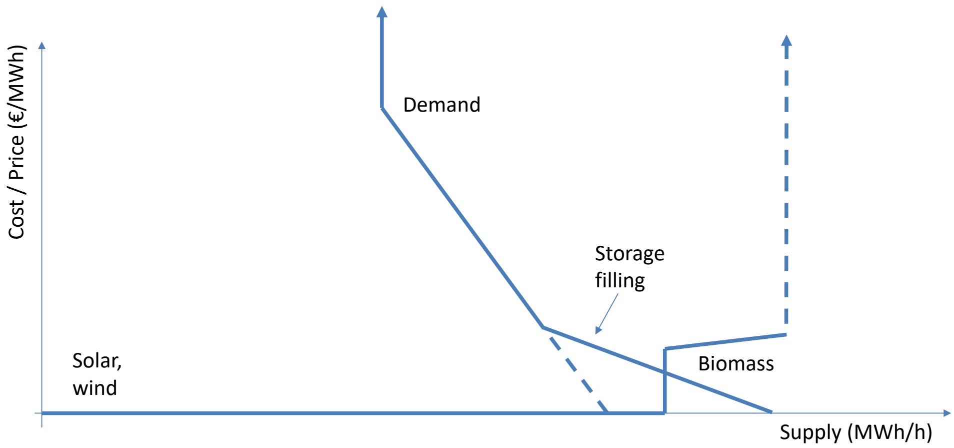

Figure 4: Price formation with ample vRES.

The figures only show two time slices; of course, in reality, both supply and demand will vary continuously and therefore the intersection between the supply and demand curves will vary continuously as well. The addition of other technologies to this stylized example, such as hydrogen power plants, nuclear power or fossil fuel with CCS, would not change the principle. The key issue is that the total volume of flexible generation and demand must be enough to ensure that there always is a match between supply and demand. A challenge in this respect is that the flexibility of consumers to shift demand tends to be limited to a timespan of several hours or, in the case of electric vehicles, perhaps a few days. A second challenge is that energy storage facilities have a limited capacity to store energy, which means that they cannot produce the same amount indefinitely, like conventional plants. Consequently, system adequacy has a time dimension: the ability of supply to meet demand at a certain time is a function of the history of the system, namely how much load was shifted in the past and the state of charge of the energy storage facilities. Section 5.4 elaborates on the long-term aspects of market design.

The dynamics of load shifting and storage operation are not optimally served by the current practice of establishing all 24 hourly prices of a day at once, as these prices may induce significant shifts in supply and demand within this timeframe. The current design of day-ahead, intra-day and balancing markets therefore needs to be reconsidered with goals being the reduction of vRESs' weather uncertainty and the optimal consideration of all types of flexibility resources, the small-scale distributed resources like household demand responsive assets and home batteries, inclusive. A possible solution is the implementation of auctions in the intra-day market that can assist in shrinking the time between trade and delivery (Ehrenmann et al., 2019).

Flexible demand and storage operators would like to arbitrage between electricity prices at different moments so they know the benefit of shifting demand or storing energy. Ideally, flexibility providers optimize their actions over a rolling time horizon, e.g. to benefit from peaks in vRES or to save stored energy for demand peaks. The establishment of micro-forward markets, e.g. markets for electricity trade up to several days into the future, could support this, but how to implement this is not clear.

A final point of attention is the volatility of electricity prices, as this creates risk for consumers and investors alike. If the market does not provide sufficient risk-hedging options such as long-term contracts, there may be a need to provide them through the market design. As this relates to investment security, we address this topic in Section 5.4.

In some current European electricity markets, renewable energy generators benefit from being prioritized in the merit-order dispatch, as a consequence of which they are only curtailed when the technical limits are reached or when there have been a number of hours with negative prices. The reason for this rule is the assumption that curtailment would increase CO_2 emissions and system operating costs. However, this rule provides an unnecessary constraint that actually may be counterproductive in some cases. For example, when demand increases rapidly, e.g. during the morning peak, curtailing wind production for a brief period before a fast increase in demand can avoid the start-up of the a fast but less efficient peak generator, allowing a less expensive but slower generation to ramp up (Morales-España & Sijm, 2020).

In summary, some of the key shortcomings of the current market design for a renewable energy system are:

- The lead times between market closure and delivery time are long;
- There may be insufficient arbitrage opportunities over a rolling time horizon of several days;
- The priority grid access that is provided to renewable energy can cause inefficiencies;
- There is a lack of incentive compatibility regarding the different types of flexibility, both on the supply and the demand sides.

5.2 Retail markets

The development of distributed generation, storage and flexible demand at the retail level is already changing the roles of distribution networks. These resources need to be integrated with the wholesale markets, because they may provide more cost-effective solutions than some of the large-scale technologies. For instance, smarter charging of EVs, optimal use of flexibility in electric heating, home batteries and the opportunity to curtail residential solar generation may cost less than centralized energy storage facilities or backup power generation. In order for the market to create an optimal mix of generation, storage and demand response, all these resources need to be exposed to the same economic incentives, i.e. the same market prices.

However, the market design should also consider the fact that local flexibility resources that respond to wholesale prices may create flows that exceed the capacity of the electricity network, especially distribution networks. Therefore, distribution network congestion management will be needed (in addition to transmission network congestion management, which already exists), as well as some organizational mode that allows small prosumers to participate in the electricity with minimal active involvement. Distribution network congestion management differs from the transmission level in that the distribution network tends to be operated in a radial manner, while transmission networks often are meshed. There are two different cases: too much local generation and too much local consumption.

The first case may occur when there is a high volume of local generation, e.g. photovoltaic generation, and local demand is low. In this case, the congestion management would need to provide a signal to curtail some local generation or activate local flexible demand. Curtailment occurs in a renewable energy system as a result of cost optimization. A high volume of vRES capacity is needed for times when their output rates are low. At times when there is a surplus of vRES, it does not always pay to store all of it. In other words, there will be times when the value of surplus energy is lower than the cost of storage.

The question of how to curtail efficiently is a challenge for renewable energy market design. Various congestion management mechanisms, including locational marginal pricing (‘nodal pricing’), zonal pricing and flexibility markets can be applied. Optimal curtailment also implies that all flexibility options are optimally deployed, in order to curtail vRES only when there is no better alternative. Various initiatives exist to limit vRES curtailment, such as the NODES marketplace[7].

A particular challenge is how to provide a signal to curtail a certain limited volume of generation, e.g. a certain share of solar PV in a distribution network, because congestion management methods tend to rely on price signals and solar PV has zero marginal cost. As a result, all solar PV installations may respond simultaneously to a change in the local energy price. A difficulty with market-based instruments is that PV panels all have the same marginal cost (about zero), so they may all respond in the same way to price signals.

The other case occurs when local demand exceeds the distribution network capacity. As distribution networks are dimensioned to meet current energy demand with an ample margin, this is only likely to occur when new load develops rapidly. A first case that is expected is when a large number of electric vehicles are charged at the same time, for instance because they all respond in the same way to the wholesale electricity price. Batteries and electric heat installations may exhibit the same behavior. The solution would be to shift part of this flexible load to other hours; the additional cost to these consumers would be minimal (Verzijlbergh et al., 2014). An open question is how to coordinate that, i.e. via a flexibility market, locational marginal pricing, via the tariff system (allowing the DSO to control consumers in exchange for e.g. lower network tariffs) or through a different type of congestion management mechanism.

A challenge is how to involve small consumers. A first requirement is that they are exposed to the real-time electricity price (perhaps adjusted for the existence of congestion). However, this is not a sufficient condition for involving them, because for households and small businesses, the transaction costs of being active in the power market themselves are prohibitively high. Therefore, the participation of their generation and flexible consumption should either be automated or controlled by a third party. Candidates for this latter role are retail companies, independent aggregators, consumer cooperatives and energy communities. Across Europe, an increase in such consumer cooperatives or communities can be observed. Some of them focus on generation and self-consumption, while others also manage local grids and operate local marketplaces to trade self-generated energy within the community. As, on the one hand, most of these communities still rely on security provided by the overall system and, on the other hand, the market could generally benefit from their flexible generation and demand, it is still an open question how to integrate these local markets into large scale wholesale energy markets and how to fairly make them contribute to the overall system costs.

In conclusion, current market design does not provide adequate incentives for the integration of retail and wholesale markets. Generation and flexibility resources at the retail level are often not even exposed to dynamic prices. In addition, distribution grid conges-

[7] https://nodesmarket.com

tion management is just beginning to be implemented; current methods are far from optimal.

5.3 Ancillary Services

In a future market with nearly 100% renewables, the demand for flexibility is expected to be higher, possibly causing an increase in the value and prices of ancillary services. Consequently, it is a priority to enable more technologies and aggregators to provide these services (Poplavskaya & De Vries, 2020; Strbac et al., 2021). Balancing markets are highly complex and undue restrictions to participation make them vulnerable to market power abuse (Poplavskaya et al., 2020).

Currently, ancillary service markets in Europe are cleared separately and therefore ignore the time dependent properties that can have an effect of each other and diminish their value. As an example, Imperial College London quantified the value of frequency response provided by controlled thermal loads. After providing frequency reserve for a period, these loads tend to increase their demand. This load recovery effect may increase the secondary reserve requirements and may imply a lower frequency response value. As vRES develops into a mainstay of the energy system, it needs to participate fully in ancillary services markets, both on the side of paying for its costs (e.g. imbalances) and on the side of being allowed to provide ancillary services (Strbac et al., 2021).

Reserve product resolutions (in time) can provide entry limitations to vRES power plants. As described in Hirth & Ziegenhagen (2015), the reserves maximum resolution for which the product can be bid into the market can be classified as static and dynamic. These mechanisms could impact the role of vRES as a balancing source and not only a cause of imbalance. Reserves can be determined for extended periods (statically), i.e. yearly, monthly or weekly, or in shorter periods (dynamically), i.e., hourly, quarterly. vRES and demand response providers cannot commit reserve capacity in long time frames in a static reserve's determination due to their aforementioned stochastic nature. Compared to conventional generators that base their bids on variable costs that are more predictable, vRES producers base their bids on opportunity costs. TSOs might not be eager to change to a shorter time frame since there is the concern that the risk of failing to contract adequate reserves could increase. Moreover, a daily adjustment of required volume of reserve needs will require a probabilistic assessment of the forecast errors of vRES.

In addition to enabling large scale vRES participation in balancing markets, the design of a new market should also enable the participation of distributed energy sources (DERs) including demand response, battery energy storage systems (BESS) and distributed vRES generation. This presents a new challenge since TSOs are in charge of creating the conditions for the uptake of new products and ensuring a reliable system operation. With this paradigm, where consumers are now also producers ('prosumers') and more uncertainty is introduced on the distribution side, there is an increasing need for greater TSO-DSO coordination.

Two design parameters that restrict the integration of vRES and DERs to balancing markets are the minimum bid sizes and symmetrical products. These parameters can be restrictive to some market participants when thinking about a power system close to 100% renewable energy penetration. Minimum bid sizes can range from 1 MW to over 10 MW for frequency restoration reserves across Europe (BMWi, 2015; ENTSO-E WGAS, 2020). It is worth noting that several TSOs are starting to lower their minimum sizes bids. Smaller minimum bid sizes will lower the entry barriers for a specific set of technologies.

Symmetrical products are another critical point of discussion. The bundling of upwards and downwards balancing products limit the amount of capacity and technologies that can enter the market. For example, if a gas producer is operating at its minimum output level, it could not offer downward regulation. A solar power plant producing at its peak would not provide upward regulation. Currently, the FCR (frequency containment reserve) is still mainly procured as symmetrical products, whereas the FRR (frequency restoration reserves) tends to be non-symmetrical.

The sizing of reserves also presents areas for improvement. Currently, the sizing is done in a deterministic or a probabilistic way. Deterministic approaches size the amount of reserves based on a specific event. For example, in the Netherlands, the size of the FRR (secondary control) is based on the largest imbalance that can occur from an instantaneous change of power of a generator, a single demand facility, a single HVDC interconnector or the tripping of an AC line (TenneT). Compared to this approach, a probabilistic sizing of reserves requires advanced forecasting tools and probability distributions for imbalance sources. Deterministic approaches followed across Europe can be suitable for current operations. However, when a higher degree of renewables enters the system, and more uncertainty is added, this approach could not correctly reflect the need for reserves.

Currently, balancing markets in Europe have pay-as-cleared (marginal pricing), pay-as-bid and regulated prices, depending on the country. There are different benefits and drawbacks from one to another. The 2019 Ancillary Services Survey conducted by ENTSO-E shows no homogeneity on which pricing rule is used for a broad set of products. Pay-as-bid can introduce inefficiencies (L. J. De Vries & Hakvoort, 2002; Schittekatte et al., 2020), e.g., in pay-as-bid generators depart from bidding their marginal costs. If a bid reflects only the generators marginal cost and is activated, there would not be any compensation for their fixed costs or profits. With bids exceeding the marginal costs and based on strategic behavior, the total cost-minimizing merit order dispatch is not guaranteed. The EBGL (Article 30, §1.a) states that the balancing market should be based on pay-as-cleared scheme. Nevertheless, if the TSOs detect inefficiencies, an amendment can be requested, and a more efficient pricing method can be proposed.

Finally, another issue regarding the provision of ancillary services has been identified, namely, power system inertia. As discussed in the deliverable 3.1, inertia plays an essential role in frequency stability. Decommissioning traditional plants to give way to new vRES plants will reduce the inertia in the power system. As a consequence, the time in which flexibility has to act will decrease. Currently, balancing markets offer reserves with typical response times of seconds. Nevertheless, this response time will have to be lower and time-dependent when synchronous power plants are on/offline. This will require new specialized market products or regulated actions taken by the TSOs to ensure system stability.

5.4 System adequacy

The objective of long-term market design is to provide incentives for adequate investments. In the past, this only concerned generation; in a future system, the objective is an optimal balance of variable renewable generation, controllable generation, storage and demand response, and an optimal combination between these market-driven investments and network capacity.

In 1978, Fred Schweppe laid the roots for the theory of spot pricing (F.C. Schweppe, 1978). Later, he and Michael Caramanis showed that spot pricing not only should lead to optimal allocation of existing generation resources, but also top optimal investment incentives for electricity generation (Caramanis et al., 1982; Schweppe, 1982). This became a leading principle for the liberalization of electricity markets around the world. While Schweppe and Caramanis initially had assumed that spot prices would elicit a substantial volume of demand response, Stoft (2002) showed that the theory still holds and will continue to provide economically optimal incentives if electricity demand is perfectly inelastic, as long as the market price cap is equal to the average value of lost load. The theory was widely accepted at the time of liberalization (cf. (Hirst & Hadley, 1999; Hunt & Shuttleworth, 1996)).

The theory is predicated on a number of requirements:

- There should be effective competition, without significant market power and with free entry and exit for market parties;
- The price cap needs to equal the average value of lost load in case load is not sufficiently price elastic to avoid shortages; in case of sufficient demand response, prices should reflect the opportunity cost of demand;
- Investors should know the future expected values and probability distributions of the prices of all inputs (fuels, CO_2 allowances) and of the electricity price itself;
- Investors should be risk-neutral;
- Markets easily reach an investment equilibrium, i.e. there are no investment cycles.

In principle, the theory also holds for low-carbon systems, as the same incentives that provide for investment in generation capacity in a conventional system should induce investment in storage and demand response in a future system. However, all the requirements for this theory, included in the above list, are difficult to be satisfied in practice.

Firstly, electricity markets are often concentrated and not rarely dominated by a single market party[8]. However, as an oligopoly may have as a strategy to provide sufficient gen-

[8] France, Belgium, Greece, Czechia, Slovakia, Latvia and Estonia, as well as some smaller European member states, have generation companies that serve more than half their markets, while Portugal, Ireland, and Sweden have companies with a market share larger than 40%. (Source: Eurostat, 2021.)

eration capacity, both to deter new market entrants and to avoid too much public scrutiny, this is not necessarily a risk to system adequacy.

There has been much discussion about price caps in electricity markets. In the USA, in the PJM, New York and New England markets, a cap of 1000 $/MWh was applied from the moment that competition was introduced. As this clearly was below the average value of lost load, it led to the 'missing money' discussion (Cramton & Stoft, 2006; Joskow, 2008). The reduced expectation of profit for generation companies due to the price cap justified the introduction of a capacity market.

The requirement that investors have a clear view of future prices and their probability distributions is not met in markets during the energy transition. Markets with a high share of vRES may have high price volatility, depending on the cost and availability of flexibility options. If the long-term price distribution function cannot be determined with sufficient precision, the third condition above is not met and investors may become risk averse. The issue in weather-dependent electricity systems is compounded by the fact that some years have higher vRES output than others, leading to lower annual average electricity prices in these years. If the market provides insufficient risk hedging opportunities, this may lead to under investment.

In addition to short and long-term weather uncertainty, a main cause is regulatory uncertainty, e.g. with respect to:

- the degree and speed of the phasing out of nuclear energy, coal and later perhaps also natural gas;
- whether carbon capture and sequestration will be socially accepted and economically attractive;
- the speed at which renewable energy will continue to be developed;
- the development of network connections to other markets;
- Europe's CO_2 policy and the resulting price of CO_2 emissions.

Additional uncertainty is caused by technology development, e.g. the introduction of electric vehicles and heating, the degree to which smart grids will stimulate demand response, the development of battery technology and of power-to-X conversion.

Variable renewable energy sources depress the electricity prices when they are producing and therefore harm their own business case. In itself, the fact that more supply of a good reduces its price is nothing new, but the fact that variable renewable generators have very low marginal costs means that inframarginal rents are nearly zero when these technologies are setting the price. The solution in 'normal' markets, to store the product in order to facilitate a long-term equilibrium between supply and demand at a price close to average cost, is not cost-efficient for electricity. A key question, to be addressed by this project, is therefore to which extent additional flexibility, e.g. from sector integration and new storage technologies, and improved market design are sufficient to create a business case for the large volumes of vRES that will be needed (Strbac et al., 2021).

Another issue is that markets often are not in a long-term equilibrium. Conventional power markets are prone to investment cycles due to the long permitting and construction times of large power plants and due to their long life cycles (Bhagwat, 2016). Investment cycles are harmful to society, even if on the average, generation capacity is adequate, as periods with under investment can lead to very high costs to consumers, while the low prices during periods with excess capacity do not offset these costs. Under uncertainty, society as a whole is better off investing a little too much in power generation than risking shortages, given the high social cost of shortages (Cazalet et al., 1978; L. J. De Vries, 2004b; Neuhoff & De Vries, 2004). However, this is not in the interest of the generation companies, as excess capacity may force the average power price below average cost. In an extreme case, this may lead to bankruptcy and/or corporate takeovers and therefore to increased market concentration.

Legacy power plants may distort the investment equilibrium during the energy transition. Operation of existing power plants will continue to make economic sense as long as they earn more than their variable and short-term fixed costs, whereas investment in new plants are only made if the expectation is that they recover their full cost. Thus, legacy (fossil) plant delays the introduction of cleaner technologies. In addition, there is a risk of an investment cycle, as is observed in practice in some countries. An example is the Netherlands, where more than 3 GW of coal plants were commissioned around 2008-2010, none of which is profitable. Price spikes in electricity and/or the CO_2 market may trigger an overreaction by investors, leading to a boom-and-bust cycle (Bhagwat et al., 2017; L. J. De Vries, 2004b; Ford, 1999; Richstein, 2015).

In the long term, after the goal of a low-emission power system has been achieved, a new equilibrium may develop. The flexibility of demand and the short lead time for installing technologies such as batteries and solar PV will allow markets to respond better to supply shortages, reducing their social impact. Once the design regulation of a renewable electricity market has crystalized, renewable technology has matured and legacy power plants have been phased out, it is conceivable that the above market failures no longer exist, but this will probably not occur before 2050.

However, the weather dependence of a renewable energy system introduces a new challenge to thermal power-based systems, namely the year-on-year variations in the weather (Hydropower-based systems already are used to this). Total annual solar and wind generation varies significantly, as does their contribution to peak load. The volume of controllable capacity (generation plus storage) that is needed to withstand periodic extreme adverse weather events will not be fully needed during most years with more average weather conditions, effectively causing excess capacity during these years. This may depress the electricity prices below the cost recovery level during most years. The fact that the probability of these extreme weather occurrences is not known due to the changing climate further contributes to investment risk. Long-term weather uncertainty also affects investment in vRES, which will experience lower returns during years with higher wind and solar generation and/or lower coincidence between their output and demand. On the other hand, society expects the energy system to maintain adequacy even during rare adverse weather events. As we saw above, under uncertainty, excess investment is a cheap form of insurance, from the perspective of society, against the much higher costs of shortages (Cazalet et al., 1978; L. J. De Vries, 2004b). Therefore, it should be studied if spot market prices are sufficient for secure capacities or some form of capacity market is required, even in the long term (Strbac et al., 2021).

In a future electricity system, storage and demand response are expected to play a significant role in maintaining system adequacy, as opposed to a conventional system in which it was a matter of generation adequacy. The current separation between wholesale and retail markets, with the latter not being exposed to short-term prices, is an obstacle to the integration of the substantive volume of distributed flexibility sources such as home batteries and demand response.

In summary, for the following reasons it is uncertain whether an energy-only market design will provide an optimal mix of investment in variable and controllable generation, energy storage and demand response:

- There is substantial regulatory and technology risk during the energy transition;
- vRES create price volatility and depress prices, reducing the business case for more investment in them;
- vRES create investment risk for controllable generation capacity, energy storage and demand response as well;
- Markets may develop an investment cycle;
- Legacy plant may distort the investment incentive for cleaner, innovative technologies during the coming decades.

5.5 Renewable support schemes

A variety of renewable support schemes have been tried by EU member states. Fixed-feed in tariffs guarantee a certain price per amount energy produced, thereby providing security to the investor. However, the risk is transferred to consumers, in the form of a levy on their electricity bills, or it is paid by the government, and therefore by the tax payers. Tradeable green certificates and renewable obligations have opposite merits, with no claim on the public budget but only a limited reduction of investment risk. More recent support schemes include components aimed at market integration of renewables, i.e. CfDs or feed-in-premia. Yet, the main incentive set by renewable support schemes paid out on the basis of produced energy and not taking into account dispatch signals from wholesale market prices is to produce as much energy as possible, which increasingly leads to issues with over production during periods with high supply and low demand. Grid integration is not or only to a limited extent included in support schemes.

The above described different support schemes of renewable energy across Europe have in common that they are designed from a national perspective aiming at promoting national renewable energy and technology targets. Due to this lack of European perspective, each country diversifies its technology portfolio, although some are more profitable in some states than in others. Bertsch & Di Cosmo (2020) show that investments in the considered technologies are not homogeneously profitable. For instance, wind power plants are relatively profitable in Northern Europe, solar and wind generate similar return in Southern countries with coastal access implying that European corporation for investment in new generation can increase overall system efficiency compared to current national climate and energy plans.

On the other hand, spatial differentiation of generation technologies has the potential to balance volatile production across regions as shown by Grams et al. (2017) for wind generation in Europe and Couto & Estanqueiro (2020) for wind and solar generation on the

Iberian peninsula. Lehmann & Söderholm (2018) demonstrate that the efficiency of renewable support schemes also depends on the general institutional framework. First steps towards a European renewable strategy are pilot projects opening their national tendering procedures for renewable energy support to other countries (e.g. Germany and Denmark). Therefore, as long as renewables still need to rely on support schemes, they should be designed in such a way that renewable energy generators are developed where they bring the highest value to the European system.

5.6 Cross-border market integration

With respect to cross-border market integration in Europe, the current system of large price zones with separate congestion management mechanisms for cross-border flows and for internal congestion has been documented to cause inefficiencies (ACER, 2020; Ehrenmann & Smeers, 2005; Hirth & Glismann, 2018; Neuhoff et al., 2011). More efficient utilization of the available transmission network capacity can be achieved through more efficient congestion management, e.g. through a change towards locational marginal pricing. In case the existing price zone model is continued, smaller price zones and improvements to the flow-based congestion management method could improve the efficiency of transmission network utilization. In addition, a change from an *n-1* transmission network security criterion to a stochastic security criterion could also improve the utilization of the networks. These changes can already be implemented in existing markets and are not unique to the question of how to design an all-renewable energy system, but implementing them would reduce the cost of the energy transition.

In the long term, more network capacity will be required. It is a question whether the current regulatory framework provides sufficient incentives to TSOs to provide the welfare-maximizing cross-border capacity and efficient utilization of the grid by applying the mentioned technical options. ENTSO-E's Ten-Year Network Development Plan (TYNDP) is created through a bottom-up process which may not result in an optimal infrastructure for the continental power system as a whole, nor in efficient coordination with the incipient hydrogen infrastructure. In any case, some network congestion is part of an optimal system, as the network capacity should only be expanded if the costs are smaller than the benefits of less congestion. Therefore, congestion management should be considered as an integral aspect of market design and not only a temporary remedy.

A second cross-border issue exists with respect to system adequacy: given a certain cross-border network capacity, how much can and should countries rely on imports for their security? At the technical level, the answer requires a demanding analysis in a case of many interconnected zones, but the more difficult problem may be the political willingness to rely on imports and the willingness to honor export contracts in case of a domestic shortage. This issue is related to the question whether there is a need for a capacity mechanism and how to design one.

While the coupling of national forward and day-ahead markets – with 27 countries being connected and actively trading – is already quite advanced, harmonization as a necessary condition for the intraday and balancing markets is still in progress. As intraday trading takes place continuously in some countries and via auctions in others, intraday coupling is still under development. The European Cross-Border Intraday (XBID) platform, which brings the European intraday continuous market together and complements the existing day-ahead market, is an example. For balancing, there are pilot projects for mechanisms such as cross-border imbalance netting. Yet, balancing products, gate closure times and the imbalance settlement period are not sufficiently harmonized for a complete coupling of the markets (Schittekatte et al., 2020).

In conclusion, several factors limit the efficiency of cross-border electricity system integration in current markets:

- Different congestion management methods are applied within and between price zones; the congestion management methods have significant inefficiencies in themselves and in combination with each other;
- Internal congestion may limit cross-border network capacity;
- The network planning process does not depart from an EU-wide welfare maximization goal but is organized in a bottom-up manner;
- Technical network operating standards can be improved to allow a higher degree of utilization;
- The design of capacity markets is focused on single countries and does not consider trade in capacity products or the ability to rely on neighboring countries during periods of scarcity;
- The design of renewable support schemes is focused on single countries and does not consider trade and the opportunity to optimize the renewable energy portfolio on a continental scale;
- Intra-day and balancing markets are not harmonized and therefore hardly coupled across borders.

5.7 Sector coupling

Sector coupling is expected to increase the flexibility of the energy system and in that way support the integration of vRES. The term is used in two ways: to indicate the electrification of demand sectors such as industrial processes, transport and space heating, and in reference to the closer integration between electricity and (an)other energy carrier. The electrification of demand sectors allows these sectors to switch from fossil fuel to renewable energy sources. It increases electricity demand, but may also add substantial flexibility to the electricity market. A sustainable alternative to direct electrification is hydrogen as an energy carrier, if it is produced with sustainable electricity (“green hydrogen”).

There is widespread consensus that a molecule-based energy vector is needed to store energy for periods when there is not enough renewable energy supply. Hydrogen is currently the most likely candidate, but other options exist, such as ammonia and methanol. This energy carrier will likely be used for much more than energy storage and power generation, for instance to decarbonize industry, transport and heating. Sector coupling is a source of opportunities for reducing carbon emissions and integrating renewable energy, but increases the complexity of the energy system. For it to be efficient, the price development mechanisms of the coupled commodities, e.g. electricity and hydrogen, as well as their network tariffs and congestion management methods need to be aligned. A difficult but important challenge will be how to coordinate the operation and the development of the electricity and hydrogen infrastructures in Europe (Gasunie & TenneT, 2019). This issue is further elaborated in the deliverable D3.4 (Kiviluoma et al., 2021).

In conclusion, sector coupling will require the alignment of market incentives among the coupled sectors, which does not only involve well-functioning and incentive compatible commodity pricing, but also alignment of taxes and levies and of the incentives provided by network tariffs.

5.8 CO_2 policy

An all-renewable electricity market will be achieved by either prohibiting CO_2 emissions or by pricing them so high that there is no incentive to use fossil fuels. In the most renewable scenarios in TradeRES, therefore, CO_2 emissions and CO_2 policy do not play a role. However, scenarios in which some CO_2 emissions are allowed are also foreseen, as well as analyses of interim steps towards a carbon-free system. In these scenarios, the possible evolution of the European Emission Trade System (ETS) will be considered. A shortcoming in the past was the volatility of the CO_2 price, leading to low prices for many years during the past decade. Backloading and the Market Stability Reserve (MSR) seem to have provided price support, but the dynamic relation between the MSR and the CO_2 price is highly complex. As a result, the CO_2 price remains uncertain, which discourages investment in carbon reduction. A minimum price for CO_2, like the UK and the Netherlands have implemented, may stimulate faster emission reduction (Richstein, 2015).

6. Energy crisis and EU policy trends in Electricity Market Design

This section aims to cover and summarize the main results from the EU public consultation on Electricity Market Design after the 2022 energy crisis. The information source is the COMMISSION STAFF WORKING DOCUMENT, Reform of Electricity Market Design that accompanies the Proposal for Regulation (EC, 2023). While the documents deal with several items, here the focus lies on the main issues relating electricity market design and the definition of policy instruments to achieve it. This serves as a basis to understand the position of different stakeholders and their views on some of the key mechanisms to deliver the transition to a renewables-based system. The consultation was launched by the European Commission on January 2023. It received 1369 contributions from citizens, companies, business associations, NGOs, public authorities, trade unions and academic institutions. The consultation had several questions separated into blocs with multiple choice and open answers.

Some of the main conclusions of stakeholders in the consultation are:

- **Support to CfDs and PPAs to derisk investment in vRES**
- **Need of mechanisms to deploy non-fossil flexibility by using capacity mechanisms**
- **Consumer protection is key but opinions differ if hedging options should be mandatory or not to retailers**

6.1 Evidence from the 2022 energy crisis

The energy crisis that hit Europe in 2022 started with increasing gas prices prior to the invasion of Ukraine by Russia because Russia stopped renewing gas contracts. After the invasion, as geopolitical energy tensions rose, further cuts in the pipeline gas supply were made, resulting in increasing prices at the Title Transfer Facility (TTF) market to over 300 €/MWh. The TTF price was above 100 €/MWh on average for longer than a year, while the prior average was between 10 and 20 €/MWh. This led to gas demand reduction, especially in the industrial sector, which helped maintain the energy balance. The gas price increases cascaded into the electricity system. Wholesale electricity prices jumped to record highs during long periods of time when gas-fired generation was setting the wholesale electricity prices while the French nuclear fleet was not fully available and Europe was in the middle of a drought. Gas and electricity prices initiated a period of inflation in the entire European economy.

With respect to electricity, Europe did not experience blackouts because the short-term energy balance was always kept in the system. The short-term wholesale electricity markets functioned as intended: the high prices caused sufficient demand reduction so the energy balance was maintained even during periods with less supply. However, this came to the cost of soaring electricity bills, both for industrial consumers and household consumers and SMEs. The market provided efficient dispatch but did not deliver the required hedging options for consumers, resulting in a call to increase the protection of consumers and rethink retail market design, and also imposing liquidity stress on some producers due to unexpectedly high margin calls. At the same time, high electricity prices led to unexpected revenues from inframarginal generators that are dependent on wholesale prices.

These events led to the conclusion that while markets are very efficient with respect to short-term operation of the energy system – and probably the only means to achieve efficient dispatch of the wide variety of means electricity generation, storage and flexibility consumption – they need to be complemented with policy instruments that ensure adequate investment in vRES and in dispatchable generation capacity and other forms of flexibility, and that protect consumers against unacceptable price spikes during energy shortage periods.

6.2 European Commission consultation

The consultation started with an analysis of the current energy crisis made by the EC. It correlated the electricity wholesale price increase with the rises in natural prices happening since the second half of 2021. The Commission states that short-term markets did perform as they were expected and are needed in the future “to ensure and efficient dispatch of all resources, maximizing renewables generation”. In contrast, long-term instruments were not in place to shield consumers from the existing volatility and high electricity prices experienced, implying a need for changes in the retail market to protect and empower consumers in the near future.

In general terms, this approach was shared by the respondents of the EU market consultation. Stakeholders agreed in the need to facilitate and ensure investment in renewable energy sources aiming to obtain it at the lowest cost possible. Access to capital is a critical element due to the cost structure of variable renewable energy projects and the risks associated with a high volatile context in their financial sustainability. In parallel with the penetration of renewables, stakeholders see the importance to promote the electrification of the energy consumption needs to facilitate the absorption of future electricity generation from renewables. The consultation points also to a need to boost and increase the flexibility of the system to adapt to the new paradigm of variable generation. Finally, there is also a consensus around the need to protect consumers from future high prices by facilitating hedging options for what they see PPAs, CfDs and forward hedging as the best options to do so.

6.3 Concrete mechanisms

The consultation had different parts and here we focus on the main issues related to the future electricity market design, not focusing in questions related to short term issues and mechanisms to such as the limits to inframarginal generators. The consultation had a focus on mechanisms to facilitate and derisk investment in variable renewable energy sources (CfDs and PPAs), to promote the inclusion of non-fossil flexibility services (demand response and storage) and consumer protection mechanisms. Regarding the first objective, some respondents warned about the possibility to experience a cannibalization effect on the wholesale market and the reduction of the liquidity in the forward markets. Forward markets are seen as a potential way of hedging consumers but the current liquidity of these markets is also seen as low.

6.3.1. Contracts for Differences (CfDs)

Stakeholders see CfDs as a positive and efficient form to support investments in new renewable capacity when it might face problems to occur on a market basis. CfDs are seen as a way to mitigate the risk of short-term price volatility both for generators and consumers by assuring a floor to renewable projects and a ceiling to consumers to part of the electricity generated during peak prices. Most of respondents did advocate for non-mandatory, non-retroactive and CfDs only for new investment, arguing that could lead to price regulation and risk of distortion on short-term markets. Other respondents do argue for mandatory and retroactive CfDs.

In general, there is a consensus that the design of CfDs is crucial to the well-functioning of the mechanism. Some of the key elements of this design principle relate to payout scheme as the decoupling of the dispatched volume to experience some exposure to market signals, obtaining the correct strike price or price corridor and the payment suspension in some situations as negative wholesale prices. The possibility to design them as a financial and none a physical contract is argued by some scholars. Issues related to the tendering process and the need of technology neutral (but only for climate friendly technologies) with competitive strike prices. Respondents also mentioned the idea of shielding CfDs from future interventions to limited revenues and raise the point of the need to design auctions considering the location to deploy renewables in a system friendly way.

6.3.2. Power Purchase Agreements (PPAs)

Stakeholders see Power Purchase Agreements (PPAs) as possibility to reduce and hedge short-term market price variations. To benefit from them, stakeholders recommend several options to increase the uptake of PPAs. Among those are to facilitate the standardisation of contracts, remove barriers to their signature, the provision of insurance against risks both publicly or market supported. Respondents do not advocate for obligations on suppliers to sign PPAs neither assume that a hedging obligation will imply the uptake of PPAs. On the other side, uptake of PPAs might reduce liquidity on short-term markets and draw a potential unequal arena with varying sized and locations between different Member States.

6.3.3. Non-fossil flexibility services

The consultation ended up with a large consent in the need to promote flexibility in the power system, especially with clear sources. In that sense, there is an overall agreement that system operators compensations need to increase the consideration of operational expenditures. In this way, some stakeholders consider that system operators will be incentivized to use existing flexibility options such as storage and demand response. Other argue for some kind of specific incentives to untap the potential use of flexibility resources by stem operators as only operational expenditure might not be enough.

The vision of demand response is positive in general but respondents advocate by general products and try to avoid specific requirements that can apply in times of crisis. A general consensus exists regarding a product to shave or shift demand in peak moments and ancillary services provided by carbon-free technologies.

The consultation provided a set of recommendations to develop flexibility assets. On the organizational side, aiming for flexibility targets, reduce minimum bid sizes on markets and flexible grid connections. In terms of price exposure, scarcity pricing, demand response incentives in contracts, local flexibility markets and locational and temporal price signals are also mentioned. And in terms of income structure, the possibility to accumulate the value provided by different markets, new market based mechanisms to provide long term signals such as capacity remuneration mechanisms.

Respondents agree, in general, on the need to continue using capacity mechanisms to ensure the required investments in demand side and storage technologies. Competition and market based tendering process are suggested to ensure an optimal playing field. Respondents also state that the current capacity mechanisms as designed are not able to deliver the required investments in firm capacity, especially regarding for the two previous technologies, storage and demand side flexibility. Some of the recommendations to facilitate the investment in them are to consider rapid variations of demand to accommodate variable renewable generation ("flexibility adequacy"), targeted remunerations as interruptibility services, assess national needs, harmonize European mechanisms and bring capacity mechanisms as a structured part of the future electricity market design. In contrast, some respondents do not see capacity mechanisms as robust enough as it is a mechanism unable to deliver a signal to all types of investment. These stakeholders suggest other support schemes as technology specific targeted programs and capacity mechanisms.

6.3.4. Consumer protection

Consumer protection is a key issue related in the electricity market reform consultation. To do so, submetering for different devices, demand response and storage is suggested by some respondents but they also rise several concerns about how this might be done and the potential to create distortions and different markets for similar types of consumers. The main options discussed in the consultation to protect consumers are mandatory offers of fixed priced contracts for small consumers, the options of a supplier of last resort and some sort of risk hedging obligations for suppliers.

Some respondents (mainly consumer associations, NGOs and public authorities) are in favor to make mandatory the need to offer fixed prices and fixed term contracts to small consumers, especially households. In contrast, other stakeholders argue that this obligation will imply a violation of the free market and argue for voluntarily fixed price contracts. A mid-way proposal argues for hybrid contracts with a band of fixed price but also part of the consumption exposed to dynamic prices. Regarding the need of having a supplier of last resort, most stakeholder agree but call to leave member states to define the specificities as retail markets differ among countries. And, most public authorities support the possibility of having emergency framework for regulate prices.

Regarding hedging obligations, most stakeholders argued in favor of setting certain levels of mandatory hedging for suppliers at least to back their fixed price contracts. Some of them argued in favor of both ensuring the possibility of new agents entering the market and to choose their own hedging strategies. In this line, some respondents suggested exceptions for small retail companies and local energy communities.

7. A new electricity market design for Europe

The main lesson that we draw from the energy crisis and from the EU's market consultation is that on the one hand, short-term energy markets should be liquid and price formation should be unrestricted, while on the other hand, both investors in the energy sector and energy consumers need protection from short-term price risk. Therefore, an important group of market design solutions that we propose is aimed at improving competition, improving the functioning of short-term markets (day-ahead, intra-day, balancing and ancillary services markets) and integrating household consumers better into the electricity market.

The second main focus of our proposed market design is the support for vRES: even in the best of worlds, vRES may not recover their investment from short-term energy prices solely and continued financial support may be needed in order to de-risk investments and assure meeting ambitious vRES expansion targets. A third pillar of market design is the design of a market instrument that de-risks investment in flexibility, in order to ensure system adequacy of supply and reliability of service, while at the same time also protects consumers from price risk.

The goal of this chapter is to identify the main features of a future electricity market design. In some cases, there is a clear argument for a certain choice. In other cases, when important choices need to be made, Work Packages 4 and 5 of the TradeRES Project will research the options.

The objectives for market design are to facilitate trade in electricity and conversion from and to other energy carriers in an economically efficient manner, considering environmental and reliability objectives. The environmental objective is interpreted as allowing only renewable energy in the most ambitious scenario in this project. We assume that the reliability will be defined as a certain performance threshold. Considering that the environmental performance is also taken as a constraint, namely (near) zero carbon, the objective of market design becomes to optimize social welfare.

This chapter follows the mentioned categories of market design decisions. The first three sections cover short-term market design elements: wholesale markets, retail markets and ancillary services markets. Next, Section 7.4 discusses investment in vRES. Section 7.5 discusses the key question of system adequacy of supply in a future electricity system. The following sections, 7.6 to 7.8, discuss several related aspects of market design: cross-border trade, sector coupling and CO_2 policy.

7.1 Wholesale market design

Wholesale market design concerns energy trade, network congestion management and ancillary services. We will discuss the first two subjects here; the provision of ancillary services is the subject of Deliverable 3.3 (van der Welle et al., 2021).

7.1.1. Energy trade

The core of the electricity market is the sequence of short-term wholesale markets. In Europe, this sequence consists of forward markets, the day-ahead market, the intra-day and the balancing markets. A reduction of the time between the wholesale market closure and the delivery time could facilitate variable renewable energy sources as well as many flexibility options. Therefore, a different organization of short-term markets is the first design variable. A possible alternative is a shift towards more frequent trading, e.g., clearing the market every hour for delivery six hours later. Another potential change is to trade shorter time blocks, e.g., blocks of 15 or 5 minutes, instead of one hour.

Therefore, a choice for European market design is whether to maintain the current organization of wholesale electricity trade, in which the 24 hours of each day are traded together at noon the day before, or to replace it with a different wholesale market design. If the wholesale market design is changed, some design variables are:

- Shorter lead times between market closure and delivery time;
- The implementation of a rolling time-horizon market clearing process;
- Trade shorter time units, e.g., of 30, 15 or 5 minutes[9];
- The organization of the intraday market (e.g., auctions or continuous trading; uniform pricing versus pay-as-bid; complex bids).

A second challenge that was identified in Section 5.1 was the need to arbitrage flexible demand and storage over a rolling time horizon. An option may be possible to create 'micro' forward markets for trading electricity in the near term, e.g., up to a week ahead (in addition to the existing longer-term forward markets), with a high temporal resolution in order to facilitate time arbitrage by storage units and flexible demand. However, this would not necessarily need to be anchored in formal market design, i.e., in the legal framework, but could be left to the power exchanges. Alternatively, this might be a function that market parties could provide themselves.

7.1.2. Transmission networks

In Europe, transmission network congestion within a control zone tends to be handled via re-dispatching. Iberian and some Nordic markets apply market splitting, which involves the creation of multiple price zones within a control zone in case of network congestion. This is an option for the rest of Europe as well, as it could lead to more efficient allocation of network capacity (Egerer et al., 2016; Trepper et al., 2015). Moreover, it is compatible with the current best practice for cross-border congestion management (see Section 5.5).

However, zonal pricing does not lead to optimal dispatch decisions in case of structural congestions (Grimm et al., 2016). Nodal pricing, also known as locational marginal pricing, as is implemented in the USA, is considered the most economically efficient congestion management method (Neuhoff et al., 2011, 2013; Weibelzahl, 2017). Yet, in terms of long-term efficiency nodal pricing does not necessarily provide sufficient hedging opportunities and can be subject to market power. Therefore, this option should be considered.

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[9] 15-minute time blocks appear to be preferred by the EC.

Aside from the choice of congestion management method, a dynamic line rating approach may increase available network capacity compared to the traditional static/seasonal line rating approach that is currently used by TSOs (Couto et al., 2020).

7.2 Retail markets

The next issue (the 'system level' dimension) concerns the challenge how to integrate decentral generation as well as flexibility options at low voltage levels with the wholesale market. The goal is to make optimal use of these resources while considering distribution network capacity constraints.

7.2.1. Retail market design

A prerequisite for involving small consumers and prosumers in the electricity market is that they receive the 'right' financial incentives, i.e. that they are exposed to the marginal cost of electricity supply in real time. There appears to be no other economically efficient way of doing this than through a form of real-time pricing, so in TradeRES we assume that future markets will involve some form of real-time pricing for all consumers, producers and prosumers. This does not mean that all consumers also experience these variable prices; instead, they may contract retail companies or aggregators to manage their flexibility for them, or a capacity mechanism like capacity subscription may be used to limit their risks.

This raises the question of how to design the 'prosumer interface': how prosumers should interact with the energy system? It is clear from the literature that consumers will not spend much time on scheduling their consumption, storage or generation devices, so this must either be fully automated (based on period preference settings by consumers) or a third party must perform these functions. Automation could take the form of flexible devices that use artificial intelligence to respond to real-time price signals, potentially through peer-to-peer trading. Third parties that could manage consumers' flexibility are retailers (or energy service companies), aggregators, energy communities and consumer cooperatives (Hobman et al., 2016). This would allow consumers to still pay a fixed rate to a retailer, who could provide them with a discount in exchange for letting him make use of their flexibility.

7.2.2. Integration of retail markets into the wholesale market

Currently, renewable energy generation at the wholesale level is incentivized differently from renewable energy generation at the distribution level. At the wholesale level, tenders for Contracts for Differences (CfD) and market premiums are commonly used to finance large projects such as wind farms. Commercial projects that are smaller and are connected to the distribution grid may also be financed in this way, but may also receive feed-in tariffs. In the retail market, where households and other prosumers may inject surpluses of energy that is generated 'behind the meter' back into the grid, net metering is common. However, because this leads to (implicit) subsidies that may be much higher than cost, there is a policy shift towards providing feed-in tariffs instead of net metering (e.g. in the Netherlands).

This solution, however, also does not provide incentive compatibility, as the time value of energy is not reflected in a feed-in tariff. However, as long as the wholesale price of electricity does not fully reflect the social cost of CO_2 emissions, real-time pricing will undervalue renewable energy generation and some form of financial support for renewable electricity generation behind the meter is warranted. However, there is no established solution that provides efficient incentives for investment in self-generation as well as for curtailment when there is a surplus. A suggestion is to include the cost of the wholesale tenders as a surcharge on the renewable energy that is delivered to end consumers, so as to provide them with a fair benchmark price for their own generation (Doorman & De Vries, 2017). However, this is also not optimal, as then the retail price no longer reflects the marginal cost precisely. It is an unsolved question, therefore, how to provide economically efficient incentives to consumers while providing a stable investment climate to vRES generators.

7.2.3. Distribution network tariffs and congestion management

The participation of prosumers in the wholesale electricity market is constrained by the capacity of the distribution network. Congestion may occur in both directions. For instance, when too many flexible loads shift towards the lowest prices on the wholesale market, there may be congestion from the transmission network to the small consumers, while at other moments, excess PV generation is already causing distribution network overload in the opposite direction. Like at the transmission level, distribution network congestion may be handled through separate congestion management methods.

Key differences with conventional transmission network congestion are that congestion at the distribution level may often be solved by shifting load over time and that the occurrence is more difficult to forecast due to the lower predictability of disaggregated load. As a result, conventional congestion pricing methods are difficult to implement, aside perhaps from locational marginal pricing. Flexibility markets, in which the DSO pays prosumers to shift load or generation, are more feasible, but also prone to market manipulation and therefore less efficient. Another type of solution may be to provide incentives for peak shaving in the distribution network tariffs (Ref-e et al., 2015), as the original reason why congestion management is needed at all is the failure of network tariffs to provide efficient incentives (because network tariffs do not reflect the short-run marginal cost of network use). An option that is currently discussed by various network companies is to charge consumers who are willing to curtail or shift their consumption during times with local network congestion a lower fixed network tariff.

7.2.4. Other financial incentives

Prosumer behavior is also influenced by other financial incentives such as electricity taxes, and levies. As they constitute a significant share of end user payments, their effects on the operational and investment behavior of prosumers may be significant.

7.2.5. Flexibility opportunities for household consumers

Providing the right financial incentives to household consumers is not enough. In order to integrate them in the market, sophisticated services need to be offered to them. Consumers do not like to spend much time on planning their flexible devices, e.g. on scheduling the charging of their electric cars. This subsection discusses how these services can be organized.

The flexibility potential was presented in the past as a mechanism used by large energy generation companies to control energy generation. This mechanism had the aim to adapt the generation to the consumption maintaining the system in equilibrium. The flexibility provided by the generation side is called supply-side flexibility. In contrast, demand-side flexibility can be obtained from flexible loads, controllable self-generation, and storage devices. Using the enumerated devices, the planned generation and consumption patterns can be adapted.

While today, there is no common standard for integrating demand-side flexibility into power systems, the Universal Smart Energy Framework (USEF) (USEF Foundation, 2015), created by the USEF Foundation, has the purpose of producing one common standard to unlock the value of flexibility. Though this framework may not cover every aspect of the heterogeneous field of demand-side flexibility inclusion and is focused on smaller scale customers, it provides a good systematization. USEF positions the aggregator in a central role of markets for procuring flexibility from smaller prosumers. In USEF Foundation (USEF Foundation, 2018), a comprehensive overview is provided of demand-side flexibility services and the opportunities for different energy system stakeholders to make use of them. Two different methods were presented for prosumers (consumer with generation capabilities) in USEF Foundation (USEF Foundation, 2019) to unlock their flexibility value, the implicit demand-side flexibility, and explicit demand-side flexibility.

Implicit demand-side flexibility is considering the uses of flexibility capabilities inside the prosumer facility, and the services that are dedicated to the prosumers. In this case, as Figure 5 presents, the services are usually provided by an energy service company (ESCo), optimizing the devices presented in the prosumer facility.

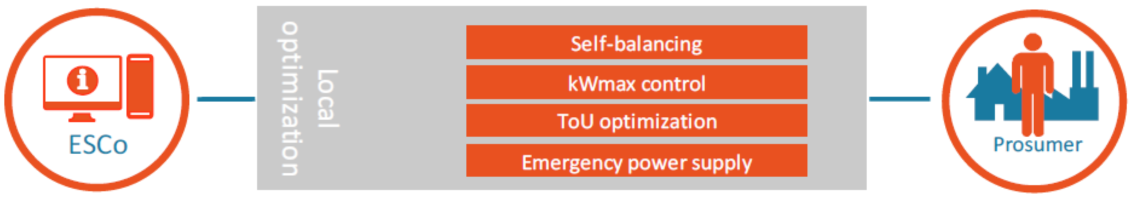

Figure 5: Implicit demand-side services (USEF Foundation, 2019)

The services provided by the ESCo can be different, as Figure 5 proposes, but all have the same purpose of unlocking the flexibility value. *Self-balancing* intends to use prosumer devices' flexibility to accumulate electricity for consumption in periods when the price is higher. Another important issue for self-balancing service is that the prosumer uses its own produced electricity. Self-consumption may be more attractive than feed-in if the remuneration is lower than the savings achieved by self-consumption. Service *kWmax control* allows prosumers to control the peak of load and avoid exceeding the capacity supply limit to cut supply or pay high costs (esp. high network charges). *Time of use* (ToU) optimization uses the flexibility abilities to adjust the consumption periods to the periods when the electricity is cheaper. The basis for that is a time-varying or dynamic tariff of demand, which can reach from ToU up to a real-time pricing (RTP) (Faruqui et al., 2012). The *emergency power supply* is a service not very common among prosumers, but it allows to store energy using the flexibility devices and consume when some emergency occurs.

The implicit demand-side flexibility can also be obtained without an ESCo. As is presented in Faia et al. (2019), the flexibility capabilities of prosumers are used to perform demand response (DR) in a standalone application. As this application is considered standalone, the prosumers should be equipped with all devices to perform the DR, representing an initial investment from the prosumer side. Concerning larger industrial consumers, an ESCo or another intermediary may not be needed as well.

Explicit demand-side flexibility is related to the use of flexibility to provide services for third-party uses. As USEF proposes in Figure 6, the aggregator has an important rule when it comes to pooling the flexibility of smaller units. With the aggregation of flexibility, it is possible to offer it to third parties that only accept a very high minimum value or to participate in markets imposing a threshold for minimum power.

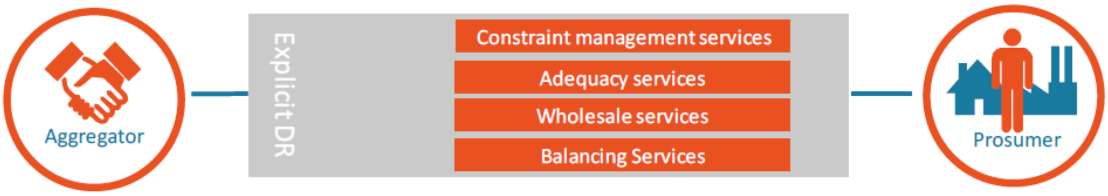

Figure 6: Explicit demand-side services (USEF Foundation, 2019)

Aggregators act as intermediaries between the prosumers and third-party entities. Aggregators have the responsibility of obtaining flexibility from prosumers. This flexibility is delivered as a service offered in different markets, and different market players can acquire it. The profit that an aggregator receives of selling flexibility should be shared with prosumers as a payment for their flexibility capabilities. For larger consumers, an aggregator may not be needed. The demand-side flexibility can be offered targeting different markets such as wholesale markets, usually the DAM or the IDM due to the short lead times and durations for providing the flexibility or reserve markets resp. Mechanisms for interruptible loads (Richstein & Hosseinioun, 2020; Wohlfarth et al., 2019).

Another option is to reduce the imbalance energy needs of balancing response parties by serving as a physical option to balance their balancing group (Deutsche Energie-Agentur (DENA), 2010). In addition, demand-side flexibility can also be used in order to address distribution network congestion. This is widely discussed in the context of flexibility mechanisms and markets (Schittekatte & Meeus, 2020).

As USEF presents the two different methods (implicit and explicit), all services presented generate benefits for prosumers in terms of their energy bill. In some cases, they allow you to receive payments for selling flexibility, and in others, it allows you to avoid paying some costs. The value of flexibility can have other purposes such as reducing operational costs of an overall system as the work presented in Faia et al. (2021) modeling peer-to-peer transactions inside of an energy community shows. Currently, energy communities and peer-to-peer-trading are being widely researched as new options for energy market design, but still with a number of unanswered design and regulatory questions (Tushar et al., 2020; Zhang et al., 2017).

7.3 Ancillary Services

The ancillary services markets will have to undergo significant changes to deal with high amounts of vRESs in the future, such as a dynamic procurement of reserves considering net load uncertainty. This section outlines some new key features future markets should include. This section is meant to be introductory. Several other aspects as minimum bid size, symmetrical products, pricing mechanisms, joint clearing of reserves and energy were discussed in Deliverable 3.3 of the project (van der Welle et al., 2021).

7.3.1. New products

Apart from the traditional reserve products FCR, FRR, and replacement reserves (RR), new products are being developed in markets worldwide to deal with the uncertainty and future demands in power systems due to the increase of vRES. Two examples are:

- Flexible ramping products – this product aims to ensure enough ramping capacity available in real-time. It should procure ramp up and ramp down flexible capacity, and its procurement and price are determined based on demand curves, which are calculated from historical forecast errors (CAISO, 2019).
- Fast frequency response (FFR) is defined by NERC (2020) as: 'power injected to (or absorbed from) the grid in response to changes in measured or observed frequency during the arresting phase of a frequency excursion event to improve the frequency nadir or initial rate-of-change of frequency'. Conventional turbine-governor responses can provide this new product, synchronous machines inertial response, wind turbine controls that extract power from the turbine's rotational energy and batteries and PVs that count with fast-responding controls.

7.3.2. New service providers

- It is still a recurring conversation up to which extent PV can provide flexibility. Currently, PV power plants can contribute to network stability and reliability through sophisticated control strategies. PV power plants can be operated flexibly, and are technically faster than conventional generators in responding to dispatch instructions. Most system operators and studies assume PV plants as must take. These assumptions treat PV output as an uncontrollable electricity source. Nevertheless, curtailment of solar output is becoming more common, whether caused by a fall in demand or transmission or operational system constraints. Flexible operating modes, such as downward and upward dispatch are possible. A PV power plant can provide up-regulation by keeping a headroom between its output and its maximum potential output. This headroom (i.e., an operational set-point) can be based on output forecasts and the prices for energy and ancillary services, or optimally obtained by a market clearing algorithm and jointly clears energy and reserves. For down-regulation, solar plants can curtail their output based on an auto governor control (AGC) signal, which dictates an instantaneous curtailment of a specific amount of energy (NREL, 2019).

- Wind turbines can provide an inertial response or fast frequency response, usually supplied by large conventional thermal generators and hydropower plants. Similar to FFR, inertial response can provide fast response and more reliable since it is inherent of generators. Wind generators can apply a retarding torque on the turbine to reduce generation. They can also increase power output for a limited amount of time (CAISO, 2019).
- Energy storage systems like batteries are a feasible option to provide fast frequency response. Battery energy storage systems (BESS) can provide active power faster and more accurately than conventional power plants. Nevertheless, the amount of reserves BESS can provide is restricted by their storage capacity.
- Different technologies applications are being explored to serve as synthetic inertia and improve systems strength and reliability. This is the case of the synchronous condenser, a well-known technology that has found a new purpose in the future's power systems. A synchronous condenser is a synchronous machine that works as a motor without being attached to an active load. It can provide reactive power, additional short circuit capacity and inertia to the system. It can consume or generate reactive power by regulating its excitation current.
- Nuclear stations are expected to satisfy the technical requirements to support and provide frequency and voltage regulation. However, this capability is limited by the need to assess the impact on reactor control and the safety case for assuming such mode of operation.
- Flexible demand is a crucial factor to undertake important challenges for the operation of the system and will play a fundamental role in the transition towards the future energy model. Demand response participation has been focused on industrial demand, being less widespread in other sectors with a more significant number of consumers like the residential and service sectors. In the coming decades, it is expected that the new measures of demand management are oriented to the services and residential, taking advantage of the new role of consumers, with greater participation and knowledge of the electric system.

Demand response can improve the adequacy of the system by reducing investment needs in peak generation. This improvement is made by shifting consumption from times with high demand. Loads are currently able to participate in some ancillary services markets across Europe. Nevertheless, there are still some entry barriers. Efficient integration of demand response in balancing markets is necessary to help achieve the traced energy policy goals in a cost-efficient manner by adding flexibility to the system.

7.4 Renewable support schemes - Investment in vRES

A key aspect of long-term system adequacy is investment in vRES. In TradeRES, it will be studied whether the market will provide sufficient investment incentives through market-based revenues. If not, a good option for providing financial support appears to be the system of tenders for well-designed two-way CfDs. Tender procedures are currently applied for offshore wind parks in Denmark, the UK and the Netherlands and in Portugal for some solar power parks. However, alternatives such as a market premium and China's FiT for a fixed number of MWh/MW in order to remunerate capacity instead of energy also have merits (Newbery et al., 2018).

In the design of support instruments, both for vRES and for system flexibility, one crucial aspect is to design them in such a way that they don't introduce unwanted distorting investment or dispatch incentives (e.g., Schlecht et al. 2023). The subset of support instruments that are already or are to be modelled within TradeRES is in line with those mentioned in chapter 9 of D4.5. In the meantime, novel instruments have been proposed such as Financial CfDs.

7.4.1. Contracts for Difference (CfDs)

Two-way CfDs are contracts where generators sell the generated electricity at market prices and afterwards they receive or pay the difference between the market price and the strike price signed in the contract. This mechanism is the one suggested in the EC proposal and provides derisking of vRES investments as it ensures prince certainty during several years to all electricity generated. By auctioning these contracts, several authors see CfDs as a viable option to reduce investment uncertainty while introducing competition in its procurement. CfDs can be auctioned by governments and benefit the whole system.

In contrast, some authors point out about certain problems that suboptimal CfD' design might generate. Among them, the main issues arising are overall suboptimal investments, negative dispatch and location incentives to investments or not enough derisking capacities. To overcome these problems, some authors suggest the possibility to use yardstick contracts as reference to enhance efficient dispatch models, derisking volumes of generation and not only prices through financial contracts and the options to have single buyers and seller of these contracts to enhance competition (Fabra, 2023; Neuhoff et al., 2023; Schittekatte & Batlle, 2023; Schlecht et al., 2023). Within TradeRES, Financial CfDs shall explicitly be analyzed as a promising instrument towards minimizing investment- and dispatch-related distortions.

7.4.2. Power Purchase Agreements (PPAs)

PPAs are long term contracts signed between generators and consumers such as big industries, corporations or utilities. PPAs trade quantities of power during large periods of time, normally lasting from 5 to 20 years, on a private basis. PPAs serve as a hedge for short-term volatility to consumers and an assured income flow for generators helping to derisk investments. However, PPAs are done on a one-by-one basis and lack of standardization. In general, due to its private nature, the literature and understanding of the system effects that PPAs might generate are scarce.

PPAs are an option to sign long term contracts and help to decrease vRES investment risks. However, different concerns exist related to their performance. First, authors fear the uncompetitive behavior seen in some PPA signature due to preferential treatment to large contractors. In this line, the confidentiality of contracts might result in a reduction of the competition among vRES penetration in the system. Second, regarding social welfare of the overall system, when signing PPAs, the benefits of vRES to the system are captured only by individual parties. In addition, the counterparty risk on the consumer-side is significantly higher compared to the state as a counterparty in state-administered support schemes (May & Neuhoff, 2021; Neuhoff et al., 2022). Third, PPAs are only a possibility for professional buyers that tend only to be large consumers and not the whole pool of consumers. In sum, PPAs by themselves are not able to motivate the needed investment in vRES (Hogan et al., 2023).

7.4.3. Other support instruments

Though not explicitly mentioned in the EU COM Market Design Proposal, there are other support instruments such as market premia, either variable (i.e. one-sided CfDs) or as a fixed top-up on market prices or capacity premia. These are also taken into account, though it is questionable whether these would be valid options in case state aid would be required to be on the basis of a two-way mechanism, i.e. foreseeing obligations to pay back in case of high price phases. These instruments are described in D4.5.

7.5 System adequacy and consumer price protection

A key issue of concern for an all-renewable system is system adequacy (Ela et al., 2018; Söder et al., 2019). The energy crisis demonstrated the profound social impact of a period of sustained high energy prices. In theory, consumers can protect themselves by buying long-term contracts. In practice, though, they do not know the value of such contracts because they do not know the risk of high prices, neither the frequency, the expected duration or how high the prices could become. Not only household consumers but businesses face this problem as well.

Providers of controllable generation capacity and storage face a mirror problem: given the same uncertainties, they do not know the value of investing in additional capacity. As a result, in an energy-only market, producers will tend to invest less, if the optimal volume of capacity is not exactly clear, in order to improve the chances of recovering their investment cost. Given the many uncertainties that increase the risk of investing in controllable electricity generation capacity and storage during the energy transition, this means that the market will likely not provide system adequacy of supply. In an ideal, fully decarbonized electricity market, weather uncertainty would be the only obstacle, with market parties investing less capacity than would be needed in cases of extremely unfavorable weather, e.g. low vRES for a prolonged period of time and either very low or very high temperatures. During the energy transition, a variety of risks (such as hydrogen import supply shocks, policy uncertainty, technology risk) contribute to this. We will test this hypothesis in the activities of the work package 5 using the models developed in Work Package 4.

While the probability and impact of energy shortages cannot be predicted, and the associated electricity price spikes therefore are a poor driver of investment, consumers can indicate the minimum amount of electricity to which they want to have access during a shortage. A market design that is based on consumers indicating their need for reliable power, rather than on them estimating the risk of shortages, is therefore more viable. This is the principle of many current proposals for the long-term design of Europe's electricity markets (Fabra, 2023; Newbery et al., 2018; Schittekatte & Batlle, 2023).

Capacity subscription is based on this principle and appears to have the potential of providing the most efficient incentives for flexibility at all system levels, but there is no practical experience (Barreto et al., 2000; Bjarghov & Doorman, 2018; Doorman et al., 2016; Doorman & De Vries, 2017). Capacity subscription is the only known capacity mechanism that provides an intrinsic incentive to behind-the-meter flexibility resources; other capacity mechanisms need to be augmented with demand response programs to achieve this goal.

However, capacity subscription falls short with respect to providing sufficient price protection for consumers. In an system in which the volume of stored energy (e.g. in the form of stored hydrogen) may also be a limiting factor, consumers may still experience high electricity prices during shortage periods. Therefore, we propose to combine this solution with the concept of reliability options (Batlle et al., 2007; Vazquez et al., 2002; Vázquez et al., 2003) which are also supported by Fabra (2023). Combining these two concepts leads to a market design with reliability options that are purchased directly by consumers, rather than by the system operator, as in the original reliability options proposal. This concept was first introduced by De Vries et al. (2004). The result would be a market in which consumers would be required to purchase a certain volume of reliability options, which would guarantee them a pre-agreed volume of electricity during shortage periods against a pre-agreed price. Consumers could decide how many of these options to purchase, vis-à-vis their opportunities for load shedding or installing their own backup power or energy storage. This market design combines the benefit of capacity subscription that consumers choose the volume of reliable capacity that they purchase with the price protection that is provided by engaging in option contracts.

An open question that needs to be addressed in the design of capacity mechanisms is: how to value the contribution of storage and demand response to system adequacy? It is increasingly possible to differentiate the security of supply that is provided to consumers, as a result of which system adequacy can be turned into a private, rather than a public good (Doorman & De Vries, 2017). This means that consumers can choose to pay less if they can be more flexible, either through their behavior or by investing in solutions like home batteries. However, no existing capacity mechanisms have a solution for including commercially operated storage facilities as peak capacity with an energy constraint. Therefore, if a capacity mechanism is implemented, regardless of the solution that is chosen, a solution for this issue will need to be developed.

7.6 Cross-border trade

The next dimension is cross-border trade between European markets. This comprises three aspects: energy trade, congestion management and, in case a capacity market is implemented, cross-border trade in capacity products.

7.6.1. Cross-border energy trade

Cross-border wholesale market integration is a requirement for the efficient integration of vRES. The harmonization and integration of day-ahead markets are well advanced in Europe, but the integration of balancing and intra-day markets has progressed less, while these will gain relevance in a near 100% renewable energy system as they are needed to balance out the variations in generation and consumption. The future design of European electricity markets should, therefore, facilitate cross-border trade optimally.

7.6.2. Cross-border congestion management

From a technical point of view, cross-border congestion management cannot be considered as separate from congestion management within a control zone, but in the current European practice, cross-border congestion management is treated separately (CACM: Commission Regulation (EU) 2015/1222 Establishing a Guideline on Capacity Allocation and Congestion Management, 2015). Market splitting and flow-based market coupling (which is a variant of market splitting) are considered as the best practice for Europe currently, if locational marginal pricing is not feasible and remediation of the congestion through network expansion is not possible or economically efficient.

7.6.3. Cross-border trade in capacity products

A different aspect is if a capacity mechanism is implemented, to what extent can capacity be traded across borders and to what extent can system adequacy rely on imports. This is an aspect of long-term market design that needs to be addressed. A question is therefore how to determine to what extent a country (or a price zone) can rely on imports for its system adequacy. A related market design question is how to include imports of capacity products in capacity mechanisms.

7.7 Sector coupling

A final issue is sector coupling. For the energy system as a whole to function reliably and economically efficiently, market design and regulation need to ensure that both investments and operation are coordinated between coupled infrastructures. This means that the design of short-term markets, the design of a capacity mechanism, if in place, network tariffs and taxes and levies all need to be coordinated between the coupled infrastructures. This topic is addressed in TradeRES Deliverable D3.4 (Kiviluoma et al., 2021).

7.8 CO_2 policy

In the strictest interpretation of the TradeRES project's scope there is no need for CO_2 policy, other than that emissions are not allowed. However, the project will also consider market configurations in which the CO_2 emissions are low but not zero, and the project will consider intermediary steps towards a zero-carbon system. For the latter two analyses, it is assumed that the European Emission Trade System (ETS), a cap-and-trade system with tradeable emission allowances, will remain in place.

The main design choice with respect to the ETS appears to be whether to add a minimum price for CO_2, like the UK and, more recently, the Netherlands have implemented. In these countries, a CO_2 is charged that tops up the carbon price if the tradeable CO_2 permit price in the ETS is below a certain level. If a minimum price were to be implemented at the European level, an alternative would be a reserve price at the auctions for CO_2 permits.

8. Market design choices

This section provides a brief overview of the identified market design choices. It will serve as a basis for decisions which of the market design elements will be included in the modeling of the design of a near 100% renewable electricity market in Work Package 4 and Work Package 5 of the TradeRES project.

Table 1 provides an overview of the market design choices. The second column describes a base case market configuration and the third column describes alternative market designs. This list should be considered as preliminary; the market design choices will be updated during the project based on further developments and the more insightful understanding of the subject matter.

Table 1: Market design choices

Market design components	Base case	Market design alternatives	Comments
Wholesale market	Current design of day-ahead, intra-day and balancing markets. Assumption of well-functioning markets by stakeholders, improvements needed to fit the penetration of vRES and flexibility.	Shorter lead times between market closure and delivery time; The implementation of a rolling time-horizon market clearing process; Trade shorter time units, e.g. of 30, 15 or 5 minutes; Different intra-day market designs; The addition of high-resolution, near-term forward markets as a product to power exchanges in order to facilitate time arbitrage by vRES, storage units and flexible demand; Other options may be considered as well, e.g. in order to facilitate new roles such as aggregators.	Various market designs may be considered. Opportunities for market power are an important aspect of short-term market design, but difficult to model. (E.g. game theoretic models or agent-based models with machine learning algorithms.)
Transmission networks	Redispatching within price zones, flow-based market coupling or market splitting between price zones	Existing congestion management methods will be compared with locational marginal pricing; A case study of the benefit of dynamic line rating with respect to reducing network congestion will be performed. Design and study of the possibilities of auctioning and how transmission rights.	The issue of transmission network congestion management is not particular to a renewable electricity market, so the development of better methods for handling it is not an objective for TradeRES. However, because network congestion is an obstacle to vRES integration, transmission congestion and existing congestion management methods will be included in the analyses. Future design might take into

			consideration the possibility to auction transmission rights be-tween market zones for periods longer than the year. This might help to boost the possibility of signing PPAs between countries.

Table 2: Market design choices (part 2)

Market design components	Base case	Market design alternatives	Comments
Retail market design	Fixed rates for small consumers, real-time pricing for large consumers.	Real-time pricing to be implemented in the entire market, also for small consumers and prosumers; To design a prosumer 'interface' and incentive structure. Opportunities for hedging in the long term for consumers such as mandatory offers at a fixed price for small consumers and standardization and larger liquidity of PPAs to ensure that larger consumers can access to them. Hybrid contracts with some band at fixed prices and other band exposed to real time pricing.	Research question: how to create a level playing field between retail and wholesale markets for vRES in case some of these are subsidized? Research question: how should prosumers interact with the energy system? Research question: how to design electricity tariffs that facilitate an efficient consumption of electricity while hedging consumers.
Distribution networks	Volumetric network tariffs for small consumers, mixed volumetric and capacity tariffs for commercial consumers	A selection of existing or proposed methods for distribution network congestion management; Innovations to network tariffs, such as capacity tariffs that are a function of consumption peak. Opportunities to include hybrid tariffs with a subscribed band of capacity and a non-firm band of capacity. Facilitate sharing electricity produced by consumers among them.	Distribution network congestion is developing as a result of decentralized generation and flexibility energy consumption. A combination of congestion management and incentives from network tariffs is needed to maintain secure operation of distribution networks in a low-carbon system. As with transmission network congestion, the development of new congestion management methods is not an objective for TradeRES, but the existence of congestion along with existing and proposed methods for handling it will be included in the project.
Ancillary services	Current division into FCR, aFRR and mFRR; Week-ahead procurement of balancing capacity; Marginal pricing (pay-as-	Smaller minimum bid sizes; Aggregation of resources; Asymmetrical bids; Passive balancing; Dynamic procurement of re-	Ancillary markets need to be reformed to allow new resources such as vRES, storage and demand response to replace thermal plant.

	cleared) for balancing energy; Minimum bid size of 1 MW; Symmetrical bids for up and down regulation required; No aggregation of resources allowed; No passive balancing allowed; No procurement of inertia by the TSO.	serves; Introduction of flexible ramping products; Introduction of fast frequency response; Procurement of inertia by TSOs. Facilitate the provision of Ancillary Services by technologies such as vRES and non-fossil flexibility services such as batteries and demand response.	Furthermore, TSOs shall adapt their balance procurement to a more weather-driven generation.

Table 3: Market design choices (part 3)

Market design components	Base case	Market design alternatives	Comments
System adequacy	Energy-only market (no support for system adequacy nor for vRES)	One or more capacity mechanisms will be studied. Candidates are a capacity market and capacity subscription. A key criterion will be to what extent they achieve integration of all flexibility options. Tenders for large-scale vRES; implicit support for small-scale vRES by adding cost of tenders to retail price.	Research question: does government need intervene to maintain system adequacy? Market design question: how to value the contribution of storage to system adequacy? Should other support instruments also be considered?
Cross-border trade: energy	Day-ahead markets are coupled, but intra-day and balancing markets not. Network constraints are allocated through flow-based market coupling. Bidding zone configuration as of today	Intra-day and balancing markets are coupled across borders. Locational marginal pricing (LMP, nodal pricing); Capacity mechanism design choice: whether and how to allow resources from neighboring markets to provide capacity. Study of the possibilities of auctioning and how transmission rights.	Which intra-day and balancing market design are needed for efficient cross-border trade in a near 100% RES system? Research question: how to determine to what extent a country (or a price zone) can rely on imports for its system adequacy? Design of the critical parameters to auction transmission rights
Sector coupling	Spot market for H_2, H_2 network tariffs	Design of short-term markets for electricity and hydrogen; Adjustment of network tariffs for electricity and hydrogen.	Research question: which design of markets and network regulation achieves optimal performance of the integrated system? Inclusion of H_2 in the mechanism to integrate non-fossil flexibility services?
CO_2 policy	The ETS in its current form	A minimum price for CO_2. In all-renewable scenarios: no CO_2 emissions allowed.	Study scenarios with different CO2 price levels and evolutions.

Market design components	Base case	Market design alternatives	Comments
vRES support schemes	No support	CfD, feed-in-premiums, capacity premiums, PPAs. Mandatory CfDs or not, retroactive CfDs or not	Are support instruments needed for financing vRESs and if so, how should they be designed? Are PPAs sufficient to deliver the required investment in vRES? Modelling of different designs of CfDs Analysis of the system performance under different CfDs designs
Taxes and levies	Not considered	Included in the analysis	

The market design changes that will be needed to achieve a reliable and cost efficient clean energy system fall into three categories. The first is the need to secure adequate investment in both vRES and flexible resources. During the energy transition, investors are confronted with technological, market and regulatory uncertainty. A question that will be investigated in TradeRES is to what extent a steady-state renewable energy market can be expected to provide adequacy. The second category of market design changes concerns the need to operate a wide variety of resources, from generation to demand response and from wholesale to retail, smoothly and efficiently. The last category is the need to design the markets, the regulation of the electricity networks and the coupling with other energy vectors in an economically efficient manner. The next steps of the TradeRES project will investigate how these objectives can be achieved through improvements to the market design.

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