OSMOSE

OPTIMAL SYSTEM-MIX OF FLEXIBILITY SOLUTIONS FOR EUROPEAN ELECTRICITY

Candidate market mechanisms and regulatory frameworks

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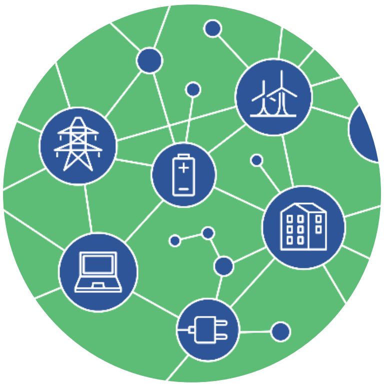

Contact: www.osmose-h2020.eu

The project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 773406

Document properties

Project Information

Programme	**O**ptimal **S**ystem-**M**ix **Of** Flexibility **S**olutions For **E**uropean Electricity
Project acronym	OSMOSE
Grant agreement number	773406
Number of the Deliverable	2.2
WP/Task related	2.2

Document information

Document Name	Candidate market mechanisms and regulatory frameworks fostering the development of flexibilities needed for 2050 RES penetration targets
Date of delivery	17/05/2019
Status and Version	Final version
Number of pages	80

Responsible

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Dissemination Level

Type (distribution level)	☒ PU, Public ☐ CO – full consortium, Confidential, only for members of the consortium (including the Commission Services) ☐ CO – some partners, Confidential, only for some partners (list of partners to be defined)

Review History

Version	Date	Reviewer	Comment
V1	25/03/19	Jens Weibezahn (TUB), Nathalie Grisey (RTE)	Update of WP1 scenarios
V2	17/05/19	Nathalie Grisey (RTE)	

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List of acronyms and abbreviations

Acronym	Meaning
aFRR	Automatic frequency restoration reserve
CGA	Current goals achieved
CAISO	California ISO
CRM	capacity remuneration mechanism
DA	Day ahead market
DER	Distributed energy resources
DSO	Distribution system operator
DSR	Demand-side response
EU ETS	European Union emission trading system
FCR	Frequency containment reserve
AT	Accelerated transformation
ICT	Information and communication technologies
ID	Intraday market
IEM	Internal energy market
ISO	Independent system operator
KPI	Key performance indicator
LMP	Locational marginal price
MD	Market design
mFRR	Manual frequency restoration reserve
MISO	Mid-continent ISO
ORDC	Operating reserve demand curve
P2P	Peer-to-peer
P2S	Peer-to-system
PJM	Pennsylvania New Jersey Maryland Interconnection
Px	Power exchange
RES	Renewable energy sources
ROC	Regional operational centre
ROCOF	Rate if change of frequency
RR	Restoration reserve
SCR	Short-circuit ratio

NCA	Neglected climate action
SPGM	Synchronous power-generating modules
TSO	Transmission system operator
VOLL	Value of lost load
VPP	Virtual power plants
VRE	Variable renewable energy technology
WP	Working package

1 Executive summary

The future is unwritten, and any "vision" of the electricity system by 2050 can only rely on the elements available today. At the same time, today is perhaps a relatively propitious moment to engage in advancing scenarios of the future electricity system. This is because a great number of new developments have been initiated over the past few years in several relevant areas. Regarding market design, these open new questions of alignment and coordination challenging existing market architectures on the following three dimensions:

1. The intertemporal dimension running from real-time operations over balancing, short-term and longer-term markets to investment decisions and the setting of environmental and energy policy objectives;
2. The spatial dimension spanning from the single node of consumption or production node at the local level, and the national grid to interconnections and the trans-national region;
3. The institutional dimension encompassing the different layers of decision-making involving different stakeholders such as consumers, producers, regulators, TSOs and DSOs as well as policymakers and the wider public.

The different outcomes of future electricity systems can only be foreseen today by the help of scenarios building. For this purpose, we depict market and regulation designs for the three following contrasting scenarios developed by the working package 1 (WP1) of the OSMOSE project: the "Current goals achieved", the "Neglected climate action" and the "Accelerated transformation". Even if a generic market design might handle coordination on the three scenarios, on behalf of the diverging underlying hypotheses behind them, it can also be expected that it's performance would be hardly satisfactory all over the range. Thus, a tailored approach towards market design appears most prudent than following a one-size-fit-all. Moreover, the most convenient way to assess this such undertake is by allocating feasible designs to scenarios, modelling their outcomes and comparing their resulting performance.

Any attempt to redesigning electricity markets should start by going back to the fundamentals of microeconomics and by a deep understanding of the microstructure of the evolving industry. The electricity sector has experienced different waves of (re)evolution during the last four decades (Hobbs and Oren 2019), it is expected that the sector will be further disrupted on the years to come due to stringent environmental standards, the uptake of new technologies with different cost structure on the supply side but also displaying different scale and scope economics, the enhanced capabilities of metering and billing on the demand-side, and the increasing establishment of platforms unleashing new ways of exchanging products and services, among other factors.

The key elements of the architecture of the electricity markets of the future already exist today. Notions of a "market" or a "price", for instance will not change. The challenge will be to articulate the different elements between the decentralized and the centralized part of the system in an appropriate fashion. Therefore, we can expect that the economic principles upon which market and regulation design have being built will remain, but the level of refinement of their practical implementation will dramatically evolve. Thus, we believe that the redesign of future electricity markets could be conveniently understood as new challenges stressing old-day issues of dealing with reliability, economic efficiency and environmental externalities.

In that way, revisiting the notion of granularity and incentives related to the spatial and temporal resolution of market products is key. But also rethinking current settlement mechanisms and re-examining the main idea of competition (i.e. “within” and “for” the market) seem relevant. On a first attempt, we propose evolutions of current market architectures as well as variations of them. For instance, a power exchange (Px) with zonal pricing (design 1.a - reference) and a power pool with nodal pricing (design 2.a - reference) need to be compared on a future with increasing needs for pricing congestions at the global and local level[1]. The considered improvements to be implemented correspond to testing higher temporal resolution, shorter lead times, including explicit flexibility products and dealing with the joint optimization of energy and reserves, but also testing enhanced reserve products. The variations of such two markets correspond to introducing local flexibility markets on the case of the Px (design 1.b), and undertaking locational prices (LMP) at the distribution level on the case of the power pool under nodal pricing (design 2.c). Also, a third variation is also considered dealing with the uptake of transactive energy markets introducing exchanging possibilities between peers (P2P) and from peers to the system operator with no further intermediaries (peer-to-system or P2S). The impacts of such platform markets should be assessed as variations of both reference types of designs, namely the power exchange (design 1d) and the power pool (design 2d). Figure 1 presents the set of market designs to be assessed and class them regarding their extent and speed of change with respect to today’s architectures.

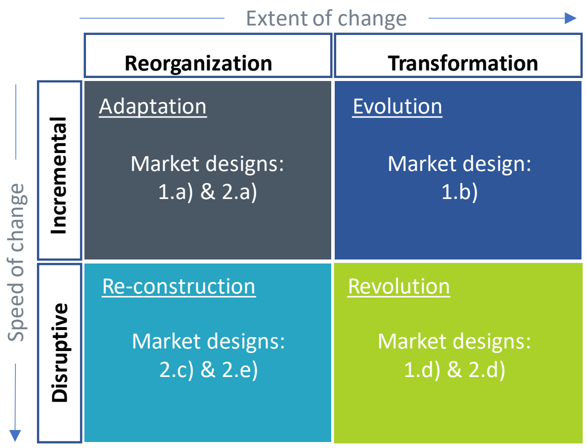

Figure 1: Market designs considered on the project

[1] Moreover, we sketch in the appendix a strawman proposal of market design based on the idea of exploitation licenses with fixed-annual ex-ante payments; so displacing competition “for the market” and requiring some degree of re-regulation.

The market designs considered are assigned to the different scenarios as depicted in

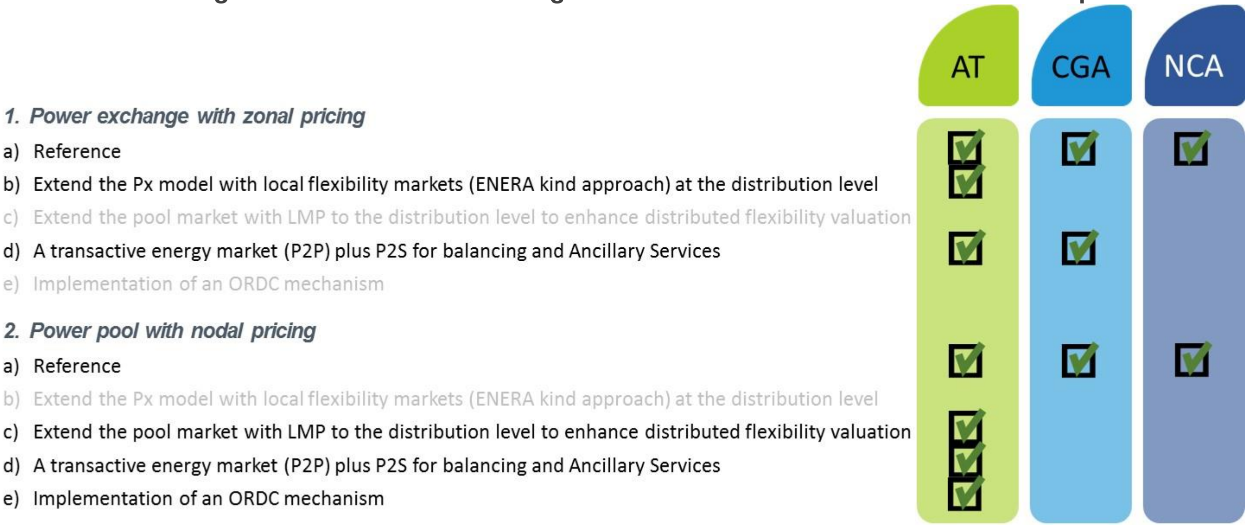

Figure 2 . It is worth noting that reference market designs, i.e. options 1.a and 2.a, are tested across the three scenarios. This is intended provide a benchmark of the theoretical economic efficiency of current market architectures on a decarbonized electricity future and would allow us to compute the efficiency gains obtained by the proposed improvements and variations.

This report presents the candidate market designs and regulation for enhancing flexibility valuation and defines the strategy to be followed during the next modelling and assessment phases of the OSMOSE's working package on market and regulation design (WP2).

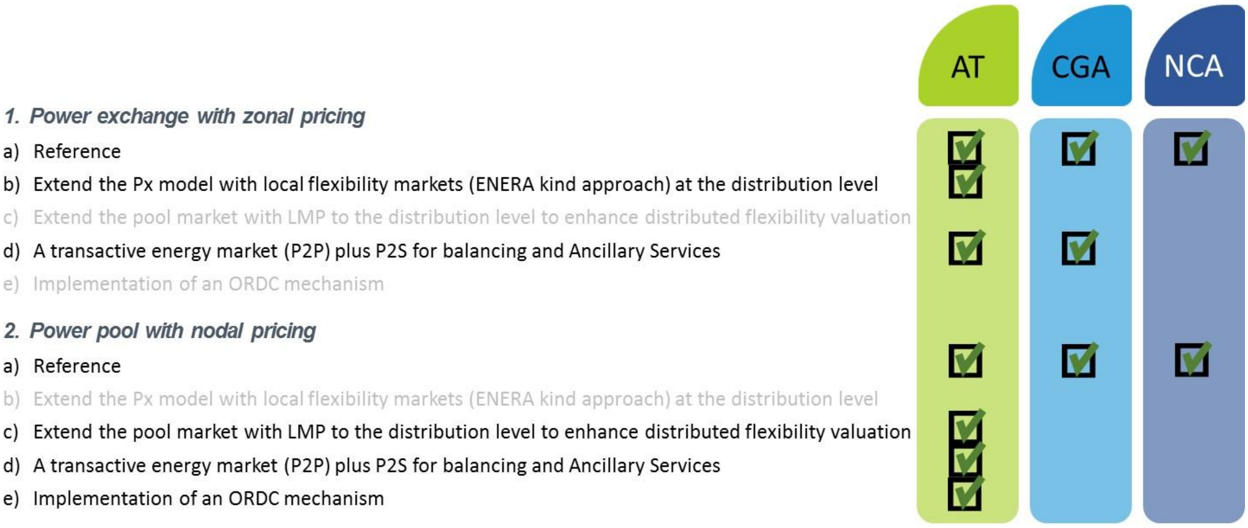

Figure 2: Allocation of market designs to scenarios – Overview

2 Introduction: system needs and services

The EU has committed on cutting at least 40% of its CO_2 emissions below 1990's level by 2030 and has declared ambitions to pursuit this trend towards 2050 with 80-95% reductions[2]. Transforming the energy systems is a top priority goal towards decarbonization. The EU's energy strategy focuses on three main levers to materialize its objectives: electrification of energy uses, fostering non-emitting energy sources and improving energy efficiency.

The report "Decarbonization Pathways" recently launched by Eurelectric (2018) sheds lights on the implications of pursuing such ambitious commitments. It affirms that "the electricity sector will lead Europe's Climate Commitments", and that "for the EU to reach 95% energy emissions reduction by 2050, direct electrification needs to supply close to 60% of final energy consumption" against current 22%. The transport and industrial sectors would be particularly targeted by electrification plans. The shift towards non-emitting energy sources should be led by a significative expansion of renewable energy sources (RES) to no less than 80% of the total electricity supply by 2045. Nuclear energy would be kept at around 15%, and the remaining shares would be represented by gas, mainly for ensuring reliability. Thus, carbon-intensive technologies like coal, lignite and fuel, would need to be completely phased-out on this horizon. Cross sectoral measures on energy efficiency would further contribute with around 30% of CO_2 reductions. This would represent a complete paradigm shift of the energy industry, which would have significative impacts over current market organization and regulatory frameworks.

Since the Third Energy Package of 2009, a "Target Model"[3] of a European electricity market has been put forward. It is based on the principles of establishing competitive zonal "Energy-only" markets based on marginal pricing, and integrating such markets by the implementation of cross-border trade through "market coupling" with flow-based transmission allocation capacity and congestion management (Keay 2013). As it was expected, the integration of national markets with harmonized rules enhanced competition and bring obvious efficiency gains, which is the main goal of creating a European Internal Energy Market (IEM). Moreover, the Third Package provided methodologies and responsibilities to the ENTSO-E for elaborating non-binding regionally coordinated plans for grid capacity expansion[4].

But "in the Commission's view inadequate market signals as well as regulatory obstacles are still frustrating progress (i.e. towards a cost-efficient transformation of the power sector): stimulating adequate levels of demand response and active prosumer participation in wholesale markets." (Hancher and Winters 2017, p11). Given the ambitious agenda on the

[2] These goals refer to the EU commitments during the Paris Agreement of 2015.

[3] The last resolution adopted regarding the New Energy Market Design is the P8 TA(2016)0333. It is available at: http://www.europarl.europa.eu/sides/getDoc.do?pubRef=-//EP//NONSGML+TA+P8-TA-2016-0333+0+DOC+PDF+V0//EN

[4] Namely, the Ten-Year Network Development Plan (TYNDP). https://www.entsoe.eu/publications/tyndp/tyndp-2016/

scope, the Fourth Energy Package (2016)[5], so called "Clean Energy for all Europeans", and the recent ENTSO-E's Network Codes[6] come to improve the "target model" for the power industry of the future. They consistently foster the goals of a deep decarbonization of the power sector, and introduce important reforms and rules to complete the IEM by addressing two missing issues directly related to new energy resources and flexibility[7]:

1. Extending the harmonization of "energy only" markets to all "wholesale markets", so requiring the creation of common guidelines and platforms for linking not only energy, but balancing and ancillary services across Europe (Meeus and Schittekatte 2018).
2. Providing a level-playing for both traditional and new market players, so ensuring a "technology-agnostic" participation of distributed energy resources (DER), demand-response (DR), energy storage, electric vehicles, aggregators, among others, on the IEM.

As commented by Hancher and Winters (2017, p5): "it is a central assumption of the Winter Package that markets cannot (reformed or otherwise) be relied upon to deliver targets on RES production by a certain deadline, otherwise those very targets would not be necessary. The Clean Energy transition package is predicated on a considerable degree of public intervention but, in contrast to the measures it seeks to replace, it has high aspirations for the effective co-ordination of that intervention at Union level."

Thus, the current EU's energy legislation considers the accomplishment of a wholly integrated IEM and the fully decarbonization of the power sector as paramount "double goals" (Lavoine 2018) and presents them as complementary. Current legislation re-emphasizes the concept of "coordination for competition" to foster the energy transition[8]. It acknowledges that markets would not necessary lead to decarbonization, it sets collective EU wide decarbonization targets and proposes monitoring and reporting mechanisms to following-up their evolution, while providing floor for national "out-of-market" support schemes for RES, as well as capacity markets. It claims for a coordinated program to limit distortions on the IEM. The function of regional coordination and governance are assigned to the new figure of Regional Operational Centres (ROCs) that will be composed by TSO's and will be under the authority of the European regulator (ACER). Moreover, the Winter Package also broadens its focus to the local dimension by encouraging the consumers to become active market participants, reinforcing DSOs responsibilities and requiring improvements on TSO-DSO cooperation. It can be considered as a real piece of "forward-looking" legislation for enabling the energy transition.

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[5] Official information on the Fourth Energy Package can be consulted at: https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition

[6] The official texts are available at: https://www.entsoe.eu/network_codes/

[7] The Fourth Energy Package also provides guidelines for implementing capacity remuneration mechanisms (CRM). CRMs are considered by the EC as last resort alternatives.

[8] The term was used by professor Hogan (2008) to describe the "counterintuitive market design condition requiring coordination for competition" during the first years of power market restructuring with the EPAct of 1992 in the US. This refers to the works of Joskow and Schmalensee (1983) and Schweppe et al. (1988) on the subject.

Nevertheless, when it comes to market design "the evil is in the details" (Oxera 2013), and there are several areas that remain unclear and/or are unaddressed in view of a future with very high shares of renewables. For instance, RES-dominated systems are mainly composed by variable renewable energy technologies (VRE) which supply is also intermittent, non-synchronous, distributed and imply very capital-intensive investments but display near-zero marginal cost. Such characteristics introduce significant temporal and spatial coordination challenges (MIT Energy Initiative 2016; Cramton 2017; Laurens J. De Vries and Verzijlbergh 2018) capable of undermining the main principles upon which the "target model" is founded.

Currently, no mentions are provided for questions such as: what kind of market coordination mechanism would exist on a near-zero marginal cost world? Would the "Electricity Target Model" still be capable of leading to productive and allocative efficiencies? Would price volatility and risk perception hinder any investment signal in a low-carbon future? Would existing price zones still be capable of handling congestions efficiently? To what extent distributed generation will shift grid management issues to the local level? What kind of local signals or markets constructs would be required to coordinate DER resources on the interface between local and global services? How flexibility can contribute to alleviating such issues? How much and what kind of flexibility would prove valuable to the system in every case? How would the evolving structure of the industry impact scope and scale economies, and network benefits? Would consumers, provided with full active participation in the market, receive incentives for pooling user-level and bulk resources? Or will consumers evaluate other attributes than the cost on their procurement choices (i.e. fuel and/or geographic origins, autarky capabilities, reliability, etc.)? How socially "optimal" would self-provisioning schemes, or even grid defection, result in a fully decarbonized future? Among other questions. The endeavors of the OSMOSE's working group on market and regulation design are articulated around such disruptive issues. Thus, the operations of future power systems and the organization of electricity markets need to evolve for accommodating such structural changes. The present study aims to explore some of the directions of this evolution.

The report "Decarbonization Pathways" not only outlines the implications of the UE's decarbonization agenda over the electricity sector, but also highlights that a full carbon neutrality by 2050 would, inter alia, require: strong political commitment across all regions and sectors of the economy for achieving objectives; a notion of fairness and justice on treating every member state with its particular economic constraints, natural endowments and technology adoption, so no region should be left behind; efficient cost allocation frameworks and market designs to address the investment and coordination challenges of a RES-dominated power system; the active role of consumers and their involvement on a more decentralized system will be a key enabler; the increasing importance of distributions networks as the physical layer integrating decentralized resources, consumers and for managing new local issues, among other (EURELECTRIC 2018). In line with these conclusions, the purpose of the present study is to add refinement and provide recommendations for the design of future European wholesale electricity markets while considering ongoing legislation. By adopting a silo-breaking approach, it focusses on the main aspects of market design for closing the existing loopholes related to harnessing flexibility for renewable energy integration.

The remainder of the report is organized as follows: Section 3 proposes a sketch of the future and introduces further details on the drivers fostering the evolution of power systems. It also introduces the most salient considerations of the scenarios considered in OSMOSE. Section 4 offers a critical review of existing market designs, identifies some of the barriers and failures of current market architectures and exposes the main challenges for the future. Section 5 introduced the methodology proposed for market design, and presents the scenario-based strategy proposed for handling the ambiguity related to trends of climate policy and the uncertain coordination capabilities of the EU for accomplishing decarbonization commitments (i.e. as considered on the scenarios). The balancing and flexibility requirements, as well as the role of the consumer, and the increasing coordination responsibilities of DSO's belong to each scenario[9] and are explicitly considered on the range of market design under study, as presented in section 5. This section also introduces the model-based methodology to be implemented for market design. Section 0 provide conclusions and further works.

3 A brief sketch of the future

3.1 Future energy pathways

The future is unwritten, and any "vision" of the electricity system by 2050 can only rely on the elements available today. At the same time, today is perhaps a relatively propitious moment to engage in advancing scenarios of the future electricity system. This is, because a great number of new developments have been initiated over the past few years in several relevant areas. The trajectories of the evolutions under way remain yet to be defined and the brief sketch that follows proposes, prudently, a rather general scenario of what will be the main characteristics of the electricity system of the future. According to what has been previously highlighted, it would be fairly safe to expect that by 2050, the electricity system will be defined by the three Ds: (1) decarbonation, (2) digitalization and technology development, as well as (3) decentralization.

The two strategic policy issues that will shape the electricity system in 2050 will be the alignment of information flows and incentive structures in the electricity system and the division of labor between the decentralized, competitive part of the electricity system and the centralized part. These questions of alignment and coordination will concern, in particular, the following three dimensions:

1. The intertemporal dimension running from real-time operations over balancing, short-term and longer-term markets to investment decisions and the setting of environmental and energy policy objectives;
2. The spatial dimension spanning from the single node of consumption or production node over the local and the national grid to interconnections and the trans-national region;

[9] They would be generated exogenously by WP1 and are introduced as inputs to WP2 for comparing outcomes coming from the market architectures considered.

3. The institutional dimension encompassing the different layers of decision-making involving different stakeholders such as consumers, producers, regulators, TSOs and DSOs as well as policymakers and the wider public.

While it is too soon in the course of the OSMOSE project to provide definite and definitive answers on such fundamental questions in this preliminary subjection, a general principle for data sharing and the institutional set-up in 2050 can already be announced. The social contract between decentralized consumers, producers and local DSOs and those responsible for overall network and system coordination, in particular TSOs and regulators will need to be radically re-defined. The precise dividing line between the two sides of the system is yet to be determined and will vary from country to country. The role of DSOs, in particular, will need to be re-defined in this context. Whatever, the ultimate division of labor between the two sides of the system, the agenda will increasingly be set by the decentralized part of the system. This, however, does not mean that TSOs and regulators will have less work or a reduced role. On the contrary, they will be responsible for covering the increasingly unpredictable gap between local initiatives and public policy objectives such as technical system integrity, fair competition at all levels, security of supply and environmental policy objectives.

The key elements of the architecture of the electricity system of the future already exist today. Notions of a “market” or a “price”, for instance will not change. The challenge will be to articulate the different elements between the decentralized and the centralized part of the system in an appropriate fashion. However, the following five building blocks are likely to figure in any well-performing low carbon electricity system horizon 2050: a) Carbon pricing, b) Competitive markets for the provision of energy and system services, c) one or more mechanisms to support investments and provide adequate capacity, d) clear rules on transport infrastructure provision, e) socially and politically sustainable distributional arrangements[10].

3.2 Scenarios of the energy transition on the EU electricity sector

The pathways towards decarbonizing energy systems in the EU are influenced by multiple factors, including “global trends”. Therefore, consistent scenarios should be formulated by grouping and setting most influencing factors coherently. The following trends were identified by WP1[11]: World order, Technological development, Population growth, Urbanization, Growing middle class, Growing inequality, Migration, Effects of climate change, Exploitation of resources, and Environmental damages.

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[10] Self-consumption and the bi-directionality of power flows as well as the declining value of energy as a commodity driven by the uptake of near-zero marginal cost technologies, which is well understood, compared to that of the provision of capacity and system services, whose value is increasing but much more difficult to measure and to communicate, will further increase complexity. It is thus indispensable that clear lines are drawn between the private and the public value of different services and that appropriate remuneration is provided in both categories.

[11] Further information on the scenarios considered can be consulted on the report “D1.1: European Long-term Scenarios”

Based on the global trends identified and following the "Scenarios of the global fossil fuel markets" (Ansari, Holz, and Appleman 2018) from the EU SET-Nav Project[12], three contrasting scenarios were depicted by WP1. They define a broad range of possible pathways of the energy sector by 2050. The main characteristic behind them are the achievements of the decarbonization goals:

- **The "Current goals achieved" (CGA)**: This scenario assumes that the 2°C target is attained, which is traduced by 40% and 80% CO2 reductions by 2030 and 2050 respectively with respect to 1990's levels.

- **The "Neglected climate action" (NCA)**: The main assumption on this scenario is the EU failing to achieve its climate goals. It assumes that climate goals of 2030 and 2050 are missed by 5% and 10% respectively.

- **The "Accelerated transformation" (AT)**: This scenario assumes comprehensive agreement on decarbonization commitments on the global and EU contexts. This scenario assumes 55% and 98% CO2 emissions reductions by 2030 and 2050 respectively.

Other than CO2 emission constraints, hypotheses on final energy demand, fuel prices and energy policies also diverge between scenarios.

Based on the IEA's projections used for the World Energy Outlook - WEO (IEA 2017c), fuel costs for natural gas, hard coal and crude oil were obtained. The WEO 2017 considers three scenarios until 2040, i.e. "Current Policies", "New Policies" and "Sustainable Development". For the sake of simplicity, the fuel cost hypothesis adopted in ours (i.e. NCA, CGA and AT respectively) coincides with that of the WEO, where values of 2050 following the same trend.

Electricity demand is assumed to be constant until 2050 in *Current goals achieved* and until 2030 in *Neglected climate action* and *Accelerated transformation.* In the Neglected climate scenario, demand increases by 5% respectively until 2050, while the opposite applies on the Accelerated transformation scenario.

In terms of energy policies, coal and lignite phase-out were assumed by 2035, 2040 and 2045 on the AT, CGA and NCA scenarios respectively.

It is worth mentioning that the three scenarios are defined as "complete states of the world" as they comprise, explicitly or implicitly, the whole dimensioning assumptions such as climate commitments, political coordination, learning rates of technologies, technology adoption, costs of fuels and labor, demand curves, weather forecasts, among other.

[12] "SET-Nav - Navigating the Roadmap for Clean, Secure and Efficient Energy Innovation, started in April 2016 and is co-funded by the EU Horizon 2020 programme. The project intends to support strategic decision making in Europe's energy sector, enhancing innovation towards a clean, secure and efficient energy system" (SET-Nav, o. J.).

4 Review of existing market designs

4.1 Current electricity market architectures

4.1.1 Fundamentals of market design

Traditionally, ensuring temporal and spatial coordination in power system have required three interdependent organizational layers: i) Grid and generation infrastructure, which is often conceived as the hardware of the system; ii) An operation and planning desk, which is the software allowing a secure management of the system; iii) A settlement and compensation mechanism, defining rewarding schemes among consumers and suppliers. Those three layers are complemented by a regulatory authority and network codes. Those elements form the backbone of any power system either vertically integrated or restructured. After the restructuring process of electricity markets during the 90's, such layers were translated into the following three core functions[13]: 1) Network provision, 2) system operations, and 3) Market platforms.

In todays restructured markets, market and regulation design consist on engineering the whole architecture of the system which comprise: establishing the way such core functions fall on different entities, defining market platforms and trading products according to system's needs, and setting rules for ensuring market efficiency. Even if after the liberalization wave of the 90's the market platforms are considered as the key place for coordination, the past 20 years of experience has shown that they are only a necessary condition for economic efficiency. For sufficiency, independence between system operators and merchant activities needs to be enforced, but also market liquidity should be ensured, and risk hedging mechanisms should be available, so avoiding different kinds of detrimental gaming and market abuses. Therefore, regulatory frameworks put as its upmost requirement the "functional and legal unbundling" of infrastructure operation from supply activities[14], while competition authorities closely monitor the performance of markets in terms of antitrust and competition.

Moreover, market architectures are contingent to the structural characteristics of the industry[15]. They influence the suitability of different pricing schemes and trading timelines, the likeliness of participation and price sensitivity of the demand-side, the potential market power of participants, the reliability considerations that need to be met and how investment signals are perceived. The structural characteristics also outlines boundaries to deregulation. Thus,

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[13] The three core functions are developed in detail by a the MIT on their study "Utility of the Future" (2016, p.186). Furthermore, a new fourth function dealing with data management is also introduced (2016, p.199). The full report is available at: https://energy.mit.edu/research/utility-future-study/

[14] The current position towards unbundling in the EU is developed on the Commission Staff Working Paper on "The Unbundling Regime" . The official document is available at: https://ec.europa.eu/energy/sites/ener/files/documents/2010_01_21_the_unbundling_regime.pdf

[15] Following Stoft (2002a, p74), "Structure refers to properties of the market closely tied to technology and ownership". Moreover, "The cost structure" (…) as "another component of market structure, describes both the costs of generation and the costs of transmission.", but also capital and opportunity costs, as well as physical constraints.

understanding industrial structure is the starting point of market design[16]. Given that for a given context the structure use to be considered as immutable, it is admitted that the process of market design should follow the well-known ordered string “structure-architecture-rules”[17].

For instance, due to cost subadditivity and decreasing returns to scale, electricity networks are broadly considered as natural monopolies, thus, not completely suitable to competition. Hence, even in restructured markets, the regulatory authority must exert direct regulation to network providers, while limiting its role to the definition of market participation rules, while enforcing and monitoring competition on the liberalized side. In the interim, operational standards, technical requirements and planning methodologies are established in the network codes. To some extent, they contain the physical “structure” of the system (i.e. reliability requirements, connection requirements, quality of service valuation, emergency protocols, among others).

4.1.2 Two families of market design

Other than structure, current architectures of electricity markets have also been strongly conditioned by the operational procedures of the vertically integrated systems prior to restructuring, as well as by the prevailing institutional attributes defining conventions and practices. This can be stressed by comparing the most relevant characteristics of the two standing families of electricity markets, the integrated pool and the power exchange (Px). For this purpose, we take the electricity markets of the US and the EU as an example[18]:

- **The division of responsibilities between market and system operators**: Power exchanges (Px) and system operators (TSO at the transmission level, and DSOs at the distribution level) are defined as autonomous entities in most European countries. In contrast, the electricity markets in the US take the form of electricity pools. The figure of independent system operators (ISO) prevail in the US, as a single entity operating both the system and the market.
- **The ownership structures and unbundling**: In the EU, TSOs and DSOs are semi-public regulated entities that own and maintain the networks, while network owners (utilities) in the US are mainly private companies that are unbundled from ISOs.
- **The market segments, auction design and settlement**: In the EU, energy markets are configured in sequences of day-ahead (DA) hourly products and intraday markets (ID) quarter hour products[19], which auctions are closed the day before at noon and few

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[16] Regarding the structural characteristics intrinsic to the power industry, Chao and Wilson (1999, p.34) comment “unlike the private-good character of energy, transmission has substantial public-good aspects, pervasive externalities, and highly nonlinear behaviour described by Kirchhoff’s Laws.”

[17] The idea has its foundations on the literature of industrial organizations of the 50’s with the string “structure-conduct-performance”, Stoft (2002) adapts it the design of electricity markets (Stoft 2002a, p74).

[18] For an exhaustive comparison between the two families of market designs the authors refer to Green (2008).

[19] The Nord Pool, covering the Nordics, Baltics, UK and Germany, also implements a continuous bid product (XBid) on the intraday. The continuous intraday matches bids on a first-come first-served

minutes before real time respectively[20]. Reserves are procured by running independent cascade auctions over different time frameworks. The US markets are based on the two-market settlement approach with a similar DA market but only a “real-time” market on the ID with a gate closure five minutes before lead time[21]. Reserves are co-optimized with energy on the DA and ID market clearing.

- **The pricing schemes:** Locational marginal pricing (LMP), or nodal pricing, is the prevailing approach in the US. It considers the state of the grid and the technical constraints between different buses to compute prices. When congestion or losses exist, price differences appear in between adjacent nodes. Price differences send price signals of the value of injecting in one bus rather than in any other, which is the scarcity value of network capacity resulting from specific conditions (i.e. grid topology). Zonal pricing is the prevailing approach in Europe, it “is essentially a simplification of nodal pricing. The power system is artificially divided into zones within which little congestion is expected to occur. As a result, prices reflect only the previously expected, most relevant cases of transmission congestion between zones.” (MIT Energy Initiative 2016)

Even if, from an institutional viewpoint, the entities responsible for grid provision and system operation are very different in both designs, the unbundling requirements and the market-based participation leads, to some extent, to similar outcomes and some design convergences in practice between the power exchange and the integrated pool (Cramton and Stoft 2006a; Green 2008). Still, the most salient differences between them come from the architecture of their market platforms, the definition of products and their pricing schemes. For instance, the treatment of bids and the clearing mechanisms they implement are rather different: other than prices and quantities, multi-part bids in the US are also composed by ramping capabilities and other technical constrains, cleared by the ISO through a security constrained unit commitment (SCUC), with possible unilateral rescheduling actions before lead time when deemed (MIT Energy Initiative 2016, p229). In the EU, block bids and smart bids linking multiple leading times are cleared by the power exchange though the EUPHEMIA algorithm[22], while market-based rescheduling is enabled through the voluntary intraday auctions. Different clearing procedures lead to differences on the treatment of non-convexities between both architectures. Thus, "uplift" or “make-whole” payments are implemented in the US for units at the margin which bids are below the clearing price, while “paradoxically rejected bids” can be found in the

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principle. Further information available at: https://www.nordpoolgroup.com/the-power-market/Intraday-market/

[20] Because coordination between TSO and Px is challenging when approaching real time, “it is commonly accepted that a time window is necessary between market closure and physical dispatch in order for the system operator to carry out reliability procedures” (...) “the current trend is to move gate closure as close to real time as practically possible.” (MIT Energy Initiative 2016, p.231).

[21] “However, US ISOs supplement the DA market with several subsequent, but non-binding, ID processes aimed at committing additional units when considered necessary” (MIT Energy Initiative 2016, p.231) and are completed with ISO’s look-ahead forecasts.

[22] The EUPHEMIA algorithm is currently used by market operators from 26 EU countries. Further details available at: https://www.n-side.com/pcr-euphemia-algorithm-european-power-exchanges-price-coupling-electricity-market/

EU. All of which result on significative differences of risk and rent allocation between market participants. To be “in the money”, the US markets manage risk in a more centralized way by carrying forecasts and executing centralized look-ahead clearing, in case of differences, the “uplift” is used to hedge trading positions. In the EU, the risk of being “out of the money” or incurring imbalance charges should be managed by the bidders themselves, so market participants hedge it mainly by portfolio optimization, which has consequences over asset diversification and company sizes (e.g. imbalance netting).

4.1.3 Level of refinement of market settlements

The notion of granularity should be introduced to compare the effects of product definition while designing or comparing markets. Granularity refers to the temporal and spatial resolution intrinsic to market products. The temporal granularity of Day-ahead markets in the US and the EU is the same, where hourly products are cleared at noon the day before delivery, and while some differences exist on that of intraday products, until now, they lead to very similar performance when it comes to deal with limited information and forecast errors [23]. Notwithstanding, differences on market clearing [24] and time granularity lead to different requirements for closing imbalances, resulting on relevant differences on the specifications and trading schemes of balancing products and ancillary services[25].

The differences in terms of spatial granularity between both market architectures seems particularly important and has been the subject of long discussions (Bohn, Caramanis, and Schweppe 1984a; W. Hogan 1992; H. Chao and Peck 1996; Stoft 1997; Oggioni and Smeers 2013; Bohn, Caramanis, and Schweppe 1984c; Wolak 2011; Stoft 2002a; Wolak 2003; Neuhoff et al. 2013). Perfect nodal optimisation is assumed as the theoretical benchmark for the efficient capacity allocation and congestion management of grid capacity, so any depart from it would entail welfare losses. Nonetheless, nodal pricing is often questioned for many reasons. The efficiency of the LMP for inducing investment has sometimes proven low, the amount and persistency of uplift payments might be problematical, their reduced liquidity is a concern and the integration of grid flexibility requires complex calculations. There are also implementation issues related to transaction costs and political difficulties for passing from a zonal to a nodal scheme. Thus, in practice, the costs associated to nodal pricing might offset its theoretical benefits (Green 2008). The choice of the pricing scheme might present path dependencies (Cramton 2017) and lock-ins, so, any initiative to increasing social welfare by

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[23] Outcomes could change on systems with significative shares of VRE. The authors refer to (Green 2008, p114) and (MIT Energy Initiative 2016) for a detailed explanation.

[24] Oggioni and Smeers (2013, p77) highlight that while security (N-1) criteria can be straightforward implemented on the Unit Commitment (UC) algorithm of the pool-based market, “there is no direct way to introduce reliability constraints in the zonal system” of the power exchange.

[25] The authors refer to Milligan (2010), NERC (2011), and Ela, Milligan, and Kirby (2011) for detailed information about the design of balancing and ancillary services markets between the US and the EU.

adjusting temporal and spatial "granularity" should put in the balance theoretical optimality with practical "sub-optimality"[26].

4.1.4 Market linkages and arbitrages

Moreover, markets are pervaded by multiple arbitrages related to every dimension of the coordination problem. In a broad sense, Tirole (1997, p134) identifies two kinds of market arbitrages: the first deals with the "transferability of the commodity", so, goods are transferred from low-price to high-price consumers or hubs; while the second one deals with the "transferability of demand", where there is no physical transfer of the good but consumers choose between different options offered. Coming back to electricity markets, the first kind of arbitrage can be directly associated with spatial arbitrages by making abstraction that consumers are price takers and there is a price on every node or zone; the second arbitrage is related to temporal arbitrage within and/or between market segments, which is mainly exerted by suppliers[27]. As highlighted by Stoft, arbitrages can also be "implicit" or "explicit" to the design and produces market linkages which are "tremendously important on the functioning of the entire market". So, linkages and arbitrage possibilities also differ between the US and the EU markets. While linkages between energy and reserves markets are made implicit on the US by the joint optimization of both products, the EU design only can induce limited efficiency with their cascading reserve markets partially disconnected from energy bids. Arbitrages between bidding on the energy or reserve markets can lead to less efficient dispatches due to uncertainty (i.e. forecast errors), opportunity costs and information asymmetries (i.e. system operators have more accurate estimations of imbalances, rather than individual market players have) (Alvey et al. 1998; Read, Drayton-Bright, and Ring 1998; S.S. Oren 2002; Shmuel S Oren and Sioshansi 2003; González et al. 2014).

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[26] The issue seems to have regained renewed interest on current European discussions on market design (Florence School of Regulation 2019). For instance, a review of the current definition of bidding zones was launched by the *Cooperation of Energy Regulators in December 2016* (CEER). Results were revealed in 2018 as inconclusive (ENTSO-E 2018). The full report is available at: https://docstore.entsoe.eu/Documents/News/bz-review/2018-03_First_Edition_of_the_Bidding_Zone_Review.pdf

[27] This is because limited price signals use to be transferred to consumers because of technical issues (i.e. limited metering and information technologies) and/or design issues (the absence of time variant retail tariffs). The deployment of smart meters and the implementation of smart grid programs are expected to unleash the capabilities for temporal arbitration on the demand-side.

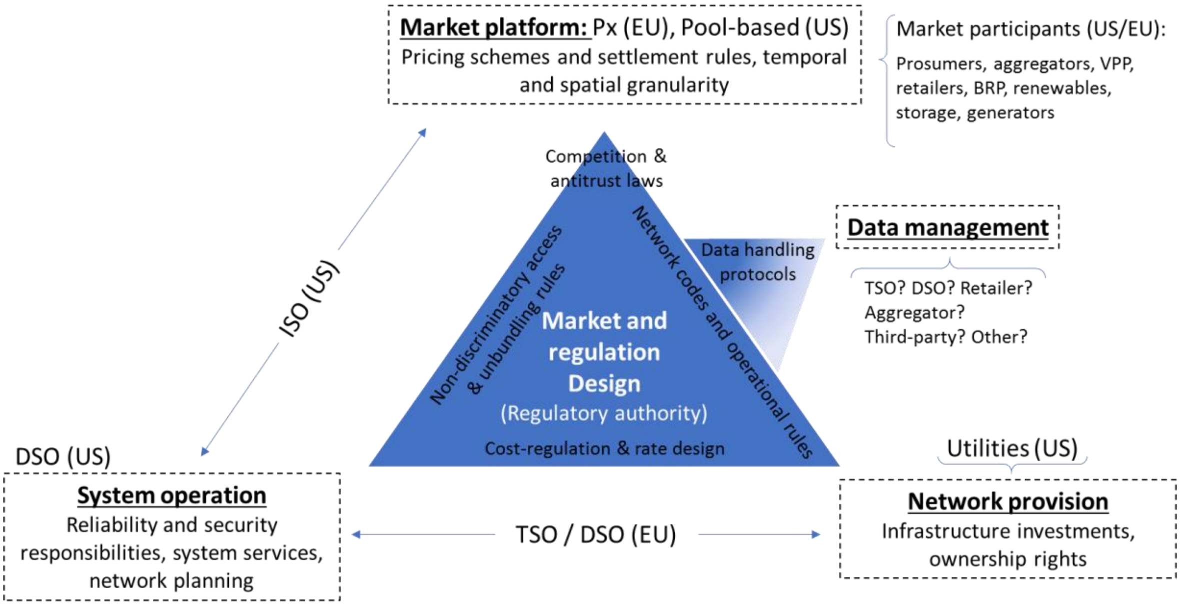

Figure 3. Core functions and entities of restructured electricity markets[28]

The market and regulation design of electricity markets, and the market architectures contained on them, are the consequence of the structural characteristics of the industry. They are conditioned by legacy industrial practices and are prone to multiple imperfections[29]. They have evolved on a trial and error process following an ever-changing setting. Thus, any attempt to designing future electricity markets should start by considering the "structure-architecture-rules" fundamentals of industrial organizations. In such way, we could enhance their anchoring with an industry under disruption[30], and proceed by balancing the possible theoretical benefits with the costs of imperfections in practice.

4.2 Old concerns but new challenges of electricity markets

Balancing electricity demand and supply means: (a) continuously balancing active and reactive power with sufficiently granular market products traded with acceptable gate closure times. Matching active power at time of delivery is equivalent to keeping system frequency at its set point (50Hz in the EU), which relates to the provision of balancing and system services; (b) Frequency regulation is needed, on a continuous basis, to compensate forecast errors of load and renewables, possible conventional power plant outages, as well as the balancing variations related to limited granularity (i.e. power ramps, energy imbalances, congestions,

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[28] Note: the figure is not pretended to be exhaustive by any means. It offers a schematic picture of current market designs, and adds the emerging fourth functionality related to data management as commented in the report "Utility of the Future" (MIT Energy Initiative 2016).

[29] Joskow (2010) provides a detailed discussion on market and regulatory imperfections on the scope of market restructuring and design, he concludes by stating "we must always come back to the question "what is the best that we can do in an imperfect world?"".

[30] While the issue on the scope of the present report is the design of electricity markets, it is worth to be noted that their real-life implementation might affect the whole architecture of the system.

among others). In the EU market this is done by a cascade strategy comprising different frequency controls[31]. Four frequency-related ancillary services can be distinguished, namely the frequency containment reserve (FCR), automatic and manual frequency restoration reserve (aFRR and mFRR), and the restoration reserve (RR)[32]; Moreover, voltage-related ancillary services (i.e. voltage regulation and reactive power supply), system restoration services, as other stability actions need also to be provided by the system operator for insuring the secure, reliable and resilient operation of the system.

4.2.1 Challenges regarding the integration of renewables

The first two decades of market restructuring has been mainly focused on aligning issues of short-term system operations with the efficient allocation of resources in the long-term while maintaining high reliability standards administratively defined (P. L. Joskow 2000; Green 2000; Wilson 2002; Cramton 2003; Cramton and Stoft 2006a; Hung-Po Chao et al. 2006; P. L. Joskow 2008). After a very detailed scrutiny of these issues, Joskow and Tirole (2007, p83) conclude: “that the combination of the unusual physical attributes of electricity and electric power networks and associated reliability considerations, limitations on metering of real-time consumer demand and responsiveness to real- time prices, restrictions on the ability to ration individual consumers, discretionary behavior by system operators, makes achieving an efficient allocation of resources with competitive wholesale and retail market mechanisms a very challenging task”. It is only with the uptake of renewables during the mid-2000’s that analysts started to realize the significative impacts and the supplementary complexity they introduce to existing market architectures (Holttinen 2005; Barth, Weber, and Swider 2008; W. W. Hogan 2008; Erik Ela et al. 2008; Hiroux and Saguan 2010; D. M. Newbery 2010; Hirth 2013; Levin and Botterud 2015; Porter, Starr, and Mills 2015a; Hirth 2015a, 2015b; Hirth, Ueckerdt, and Edenhofer 2016).

As previously exposed, future energy mixes are expected to be predominantly based on variable renewable energies (VRE), mainly wind and solar generation. On one side, VRE are carbon-free energy sources, they have attained significative maturity during the last decades which has traduced on significative cost reductions and competitivity gains. They are expected to be the main driver of decarbonizing the power sector. On the other side, their supply is not only variable but also, intermittent, non-synchronous, distributed and displays near-zero marginal cost. Such characteristics introduce significant operational challenges from the technical point of view as well as important externalities and coordination issues on current electricity markets. Ill-designed elements of electricity markets and inadequate policy schemes give rise to market inefficiencies, and the uptake of renewables severely accentuate them.

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[31] It is worth to be note that the rate of change of frequency (ROCOF) is inversely proportional to the inertia of the system. The uptake of non-synchronous generators is expected to difficult this task.

[32] A complete report describing the different ancillary services and its relationship with the flexible capabilities studied by the demonstrators of OSMOSE have been published as an internal deliverable, as well as a brief note focused on current design of the market for AS in EU. Both documents can be consulted on request.

Conventional generation technologies are composed by synchronous power-generating modules (SPGMs) which provide inertia as a by-product of real power. Once renewables reach a certain penetration level, the inertia supplied by remaining conventional power plants is no longer sufficient and imbalances might generate unauthorized frequency changes. Synthetic inertia (achieved for example by renewables) may help to a certain extent, by providing a power boost, which slows down the frequency drops. It requires an additional and costly control strategy and above a certain share of renewables, synthetic inertia becomes no longer sufficient, as the rate of change of frequency turns out to be too high to be compensated by a power boost[33]. Hence, in the transition towards a system dominated by variable renewables, the dynamics of system frequency would change, so larger frequency deviations might be expected due to smaller imbalances between supply and demand[34].

For maintaining system stability, also the voltage at all nodes must be kept within permissible limits. In contrast to frequency, voltage at the transmission grid level is mostly driven by reactive power provision or consumption. System strength is another need that has to be controlled for insuring system security[35] and which also has been indirectly provided by synchronous generators through electrical torque, such as inertia is, but at a local scale[36]. System strength is decreased by the short-circuit ratio[37] (SCR), which in turn is exacerbated by the aggregate effect of multiple electrically close non-synchronous units. Unlike the frequency control, these services must be provided locally or at least regionally, because the impact of voltage adjustments at one node decreases with distance.

Moreover, the distributed nature of VREs, such as other emerging distributed energy resources (DER, e.g., micro-generation, prosumers), will significantly change the power flows on the grid, rising further congestion and stability problems. It is expected that congestion management issues and outages will particularly increase and disseminate at the distribution level. Active monitoring of flows on the distribution network will be increasingly needed to ensure stability

[33] The MIGRATE project (Massive InteGRATion of power Electronic devices) is seeking to devise a grid-forming solution for 100% power-electronic grids (wind and solar renewables). MIGRATE has shown that two options could be considered for addressing these frequency/stability challenges: guaranteed rate of synchronous compensators running on no load or grid-forming, where certain energy sources (renewables, batteries) will have to set the frequency and minimise frequency changes on the grid.

[34] It might be expected that future systems based on AC transmission and non-synchronous units require a new system service/obligation for forming system frequency (e.g. from natural and synthetic inertia). An industrial view on this subject can be found at: https://reneweconomy.com.au/ge-grids-dont-need-rely-synchronous-generation-89161/

[35] The most relevant faults on the system are due to short-circuits, which lead to an unforeseeable local breakdown of the voltage, where generation units are essential for restoring stable grid operation.

[36] Further technical details can be found at: http://energylive.aemo.com.au/-/media/Files/Media_Centre/2017/South_Australia_System_Strength_Assessment.pdf

[37] For a transmission network, fault level can be conveniently expressed in a per-unit form, commonly referred to as short-circuit ratio (SCR). In broad terms, the lower the value of SCR, the weaker the power system will be, and vice versa. Further technical details can be found at: https://e-cigre.org/publication/671-connection-of-wind-farms-to-weak-ac-networks

and avoiding unforeseen faults[38] [39]. In this regard, any increase of non-competitive preventive measures (e.g. redispatch, countertrading, market splitting) or corrective measures[40] (e.g. brown-outs, restauration or emergency operations) would entail welfare losses.

4.2.2 Challenges regarding the organizational structure

The extent of the structural change implied by the extensive decarbonization of the power sector is of great magnitude. Any workable market design known, such as the “Standard Market Design”[41] or the “Electricity Target Model”[42], seems to become out of date when it comes to foster the cost-efficient integration of renewables on a massive scale, so requiring a significative revisions (Roques and Finon 2017; Cramton 2017; D. Newbery et al. 2018; L.J. De Vries and Verzijlbergh 2018; Ahlstrom et al. 2015; E. Ela et al. 2016; Peng and Poudineh 2017a; Conejo and Sioshansi 2018; Botterud and Auer 2018; Hu et al. 2018). Hence, the old problems of power systems and market design are being met by new challenges related to the integration of renewables[43].

[38] The most relevant faults on the system are due to short-circuits, which lead to an unforeseeable local breakdown of the voltage, where generation units are essential for restoring stable grid operation.

[39] The need of controlling the grid flows dynamically (C) has arisen in the last years, given the massive changes of the transmission flows according to the regional RES infeed (e. g. wind infeed in the north and load centers in the south of Germany).

[40] Black start as well as island operation capability are the most relevant system services in case of a partial/total blackout.

[41] In 2002 the NERC launched its docket No. RM01–12–000 documenting its Notice of Prosed Rulemaking on the “Standard Market Design” in the US. Shah et al. (2016) provide a extensive discussion on the current initiatives conducted in the US markets aiming to improve the standard model. The original document from NERC can be consulted at: https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/RM01-12-000-SMD.pdf

[42] The first EU electricity “Target Model” was launched in 2009 with the Third Energy Package. Discussions on the Fourth Energy package considers are still ongoing. The market design put forward on this package is an enhancement of the previous, also referred as “Target Model 2.0”. Further information is available at: http://www.europarl.europa.eu/sides/getDoc.do?pubRef=-//EP//NONSGML+TA+P8-TA-2016-0333+0+DOC+PDF+V0//EN

[43] The discussion on market integration of renewables has been a very active branch of literature on energy economics during the last decade. Relevant contributions has been proposed by (Green 2008; Barth, Weber, and Swider 2008; Ummels 2009; D. Newbery et al. 2018; D. M. Newbery 2010; Fink et al. 2012; Levin and Botterud 2015; Porter, Starr, and Mills 2015b; MIT Energy Initiative 2016; Hledik, Lazar, and Schwartz 2016; Shah et al. 2016; Fraile et al. 2016; Roques and Finon 2017; Glazer et al. 2017; Peng and Poudineh 2017b; Botterud and Auer 2018; L.J. De Vries and Verzijlbergh 2018; Bjørndal et al. 2018; Steven Corneli 2018; IEA 2018; Cramton 2017; William Hogan 2016; KASSAKIAN et al. 2011; Mike Hogan 2015; Parsons et al. 2008; Holttinen 2005, 2016; Van Hulle et al. 2012; Söder et al. 2012; Keane et al. 2011; Hirth, Ueckerdt, and Edenhofer 2013; Hirth 2013, 2015b; Hirth and Ziegenhagen 2015; Hirth, Ueckerdt, and Edenhofer 2016; Keppler and Cometto 2012; Musgens and Neuhoff 2006), to cite only a few of them. The literature related to the design of electricity market for low carbon power systems is often referred as “clean restructuring” (Shah et al. 2016).

This idea has been particularly well formulated by Newbery (2015, p409), where he relates well established concerns about capacity/revenue adequacy, the role and difficulties of scarcity pricing, issues of risk perception and allocation, and the difficulties of accurately valuating system reliability, with the new challenges introduced by the uptake of renewables when affirming: “Missing money and missing markets provide compelling reasons for a capacity payment (which don’t make part of the energy-only “Electricity Target Model” in the EU) in competitive electricity markets dominated by politically determined and subsidized unreliable generation and where investors lack confidence in future revenues” (…) “the part of the adequacy debate that has been neglected is how to, and who should, determine the amount and type of capacity to procure (generation, DSR, interconnection)” which has introduced significative bias (…), “The bias is further exacerbated by failing to address some of the missing market problems that have also been neglected in the debate”.

Nevertheless, it is admitted that capacity remuneration mechanisms (CRM) are a “third-best” solutions of the real and latent market failure of “missing money”. It is also commonly suggested that failures on market designs should be redressed as close as possible to their source, which is often referred by the foremost standard of “getting the prices right” on energy and reserve markets[44] (William Hogan 2014; Michael Hogan 2017; William Hogan and Pope 2017; D. Newbery et al. 2018).

Perhaps, the most comprehensive and long-lasting initiatives for understanding the impact of renewables over legacy power system and markets, which have combined contributions from academics and practitioners from multiple fields across the years, are those lead by the International Energy Agency[45] (IEA), the National Renewable Energy Laboratory[46] (NREL), the CIGRE/CIRED[47], and the Electric Power Research Institute[48] (EPRI). All of them coincide on the central role flexibility has to play as a key enabler for market and system integration of renewables. Thus, harnessing flexibility is a top priority when designing low carbon electricity

[44] Since the same assets can participate on energy and/or reserve markets, the most convenient setting is to jointly optimize them on the market clearing, so avoiding any detrimental arbitrage due to information asymmetries among market players. See (Kirschen and Strbac 2004, p121) and (González et al. 2014, p103) for a discussion on the fundamentals, and (Cramton 2017; Capros and Zampara 2017; Conejo and Sioshansi 2018) for a presentation on it benefits for renewable integration.

[45] The IEA has launched several programs dealing with the study of renewables and their integration during the last decade. Among the most salient ones are:

- The “Technology Collaboration Programs”, particularly those of wind and solar. Further information is available at: https://www.iea.org/tcp/, https://community.ieawind.org/home and http://www.iea-pvps.org/
- The “Renewable Technology Deployment (RTD)” from 2015 to 2017. Further information is available at: http://iea-retd.org/publications

[46] Relevant publications on the topic are available at: https://www.nrel.gov/grid/power-systems-design-studies.htmll ; further market design publications available here

[47] Relevant publications on the topic are available at: https://e-cigre.org/, http://www.cired.net/publications-all

[48] Relevant publications on the topic are available at: https://www.epri.com/#/research/landing?lang=en-US

markets. However, what is often less intuitive, and not always explicit, is a workable definition of flexibility. On their recent report "Utility of the Future", the MIT highlights:

> *""Flexibility" is just a concept — it is not really a service, and its value cannot be decoupled from the electricity price by implementing a separate product. To reflect the value of flexibility for the power system, the granularity of electricity prices should be aligned with dispatch instructions and reflected in reserve product design."* (MIT Energy Initiative 2016, p235)[49]

Their assertion is essentially right in theory, but partially true in practice. Even if they don't provide a categorical definition of flexibility, they approach it on a comprehensive manner of the kind: "flexibility is the ability of the power system to deal with a higher degree of uncertainty and variability in the supply-demand balance" (IEA 2017, p14). Indeed, under such definition, there is not an explicit demand for flexibility on power systems as it is for energy, nor a need on the strict sense.

By considering flexibility as a ubiquitous attribute of the system, comprising multiple stages of the power supply chain and at different scales, it becomes clear that it is closely tight with the delivery of power, so duly calibrating market granularity would improve the case for harnessing flexibility. Thus, it is often expected that introducing higher granularity on energy-only markets would trigger cost-effective flexibility attributes, adding value to the system on a case by case basis. However, given the fact that flexible functionalities are spread over the regulated and the competitive segments of the market, that their usage is disseminated among different beneficiaries, and that market granularity is often constrained due to the dimensionality issues of planning and dispatch methodologies, we can only affirm that market granularity improves the case for flexibility but whether it would be enough to harness the socially optimal levels of it remains an open question.

From a pragmatic point of view, it is possible to identify two aspects affecting the flexible attributes of a power system: the existence of "physical flexibility" itself, as the technical capabilities of assets to follow sudden variations of demand, and the "administrative flexibility", as that related to market design and product specifications (IEA 2018, p2). Both are interlinked and should be fostered for the cost-effective integration of renewables. Nevertheless, similar than network infrastructure, some applications of flexibility are the object of important external economies related to the provision of low-excludability services[50] that use to fall on the category of regulated services (i.e. reserves, transient stability, grid forming, capacity firming, non-wire alternatives to avoid/defer grid investments). Thus, in practice, even energy-only markets with very fine granularity might still fail to designate the full value of flexibility. Moreover, the amount of flexibility value that is possibly captured by energy-only markets

[49] The authors also recognize that "many power system operators, concerned with finding ways to attract flexible generating resources, have proposed the implementation of "flexibility products" that would allow them to preferentially procure electricity from the most flexible resources". (MIT Energy Initiative 2016, p235).

[50] In this context, externalities are related to "missing markets" in the sense of Arrow (1969). The authors refer to (Keppler 1998) for a detailed presentation on this issue.

through increasing granularity is a system dependent factor, and its dynamics are related to the shares of renewable energies on the system, among other. In line with this, CAISO and MISO have introduced explicit "Flexible Ramping Products", co-optimized with energy and reserves, remunerating ramping capabilities. PJM introduced the RegD product as an "energy-neutral" fast reserve product providing additional incentives to flexible units. Gottstein and Skillings (2012), and Buck et al. (2015) propose to go "beyond capacity markets" by introducing dynamic capability attributes on CRM targeting new flexibility resources. Most of the ISO's in North America are following one of these ways (Shah et al. 2016, p16).

The IEA highlights several "key operational and market issues" related to harnessing flexibility:

> *"What is the institutional setting of the future time period to be analyzed? Will markets evolve to include products that enhance flexibility, or will fast dispatch/balancing be sufficient? Should capacity markets be included? Will there be reserve markets over different time scales? Will there be any type of operational consolidation or dynamic scheduling (of generation, load, or imbalance) that will have an impact on integration? Will there be broader reserve-sharing regions? Is it allowable to deploy contingency reserves for significant wind/PV ramp events, and if so, what are the criteria for doing so? What is the assumption regarding balancing areas/zones, and what is the appropriate modelling approach to account for interchange that correctly captures actual (or future) practice? Will reliability-based balancing criteria be the same in the future?"* (IEA 2018)

Hence, traditional issues of power systems dealing with temporal and spatial coordination would be further exacerbated with increasing shares of VRE, and broadening flexible capabilities will be of interest for balancing them. Moreover, flexibility attributes would not only contribute to VRE integration, it would enhance time arbitrages (subject to technical constraints), so increasing the capacity factors of low-cost technologies by smoothing variations with energy from base-load generation when profitable, and regardless the intrinsic CO_2 emissions of doing so. In the absence of properly calibrated carbon prices coal-based generation might benefit from profitable dark spreads; thus, time arbitrages might lead to adverse effects and result on higher CO_2 emissions (Villavicencio 2017).

Well aware of the current discussions on the Fourth Energy Package in the EU, Newbery and his collaborators (2018) remark that "The EU's current Target Electricity Model is very incomplete in specifying the desirable changes" of current electricity markets on a fully decarbonized future, they highlight that the EU "Electricity Target Model" could particularly fail on accomplishing its paramount goals of decarbonization and fostering economic efficiency because "pricing is too coarse over time and space, and carbon emissions remains under-priced". They continue by stating that "the desirability of more granular temporal and spatial prices at the wholesale level applies even without reference to climate concerns as the need for more types and volumes of flexibility services[51] increases". Their vision is founded on the seminal works of (M. Caramanis, Bohn, and Schweppe 1982; F.C Schweppe et al. 1988; Bohn,

[51] It is worth noting that in the context this passage, the term "flexibility services" means harnessing services from flexible capabilities.

Caramanis, and Schweppe 1984a, 1984b; H. Chao and Peck 1996; Stoft 1997; Harvey and Hogan 2000), and recent findings of (Green 2008; Oggioni and Smeers 2013; Neuhoff et al. 2013; Bona et al. 2017; Peng and Poudineh 2017b; MIT Energy Initiative 2016; Botterud and Auer 2018; Hu et al. 2018; L.J. De Vries and Verzijlbergh 2018) support their vision.

Hu et al (Hu et al. 2018) propose a complete review of the weaknesses of current EU market design regarding the cost-effective integration of renewables and for effectively harnessing flexibility. For every market segment, they identify the main barriers that need to be improved and propose an evolution on three directions: 1) the pricing mechanisms, 2) the product specifications and granularity, and 3) providing a level playing field for market participation. Figure 4 summarizes their findings.

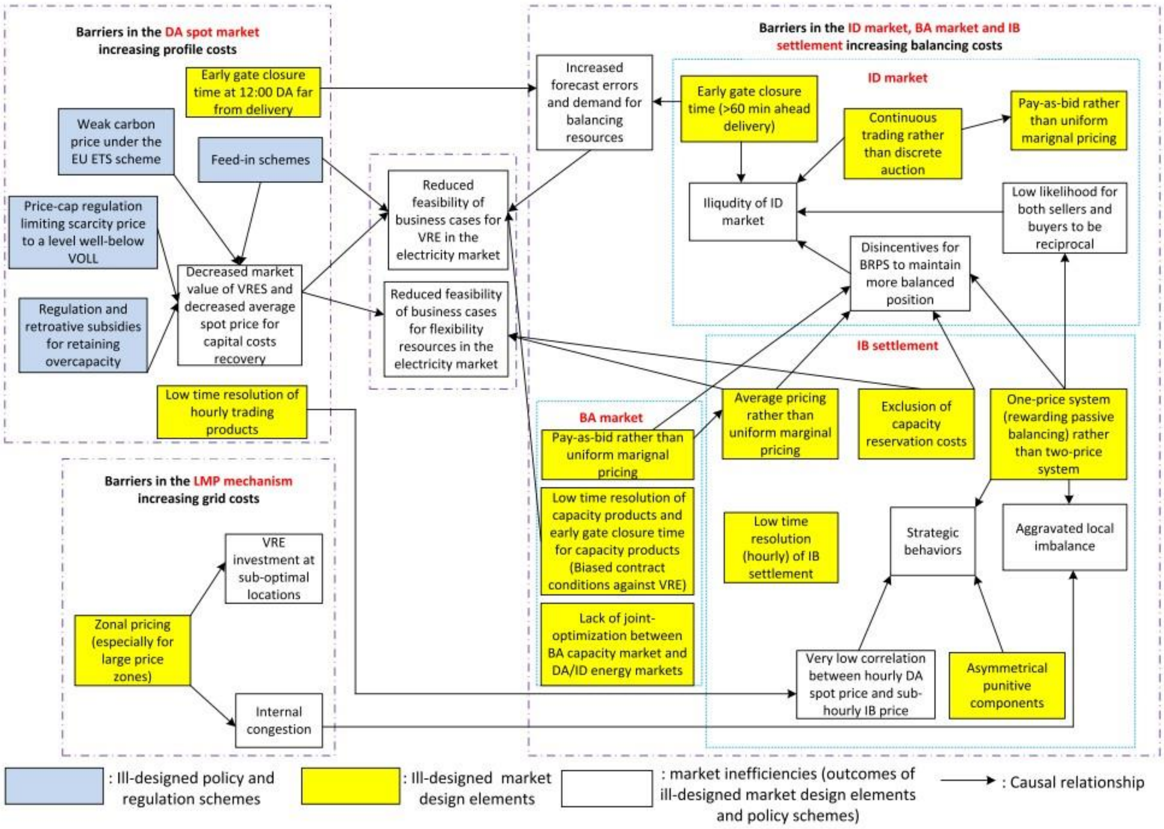

Figure 4. Market barriers for RE integration in the EU market design. Source (Hu et al. 2018).

4.2.3 Issues related to evolving market boundaries

The ongoing discussion on the Fourth Energy Package emphasizes the benefits of implementing larger and faster markets with wider participation by promoting product standardization, marginal pricing when possible, cross-border participation and a level-playing field for market participation as found by Fraile et al. (2016) and, Capros and Zampara (2017), but the topic of spatial granularity is somehow disregarded.

Notwithstanding, the value of VRE, so that of flexibility, strongly depends on their location, thus it can be expected that improving coordination along the locational dimension will be of higher importance for future market designs. If there is a lack of coordination between grid and renewables development, it is likely that congestions on existing transport lines will be exacerbated due to the infeed of higher shares of renewables[52] (Neuhoff et al. 2013; Bjørndal et al. 2018). The MIT conclude that "DERs increase the need for nodal pricing in wholesale markets, while simultaneously making it necessary to expose DERs to price signals with the same temporal and spatial resolution" (…) "price averaging (at the distribution level) will be increasingly inefficient, as low-voltage consumers start responding to price signals, both in the short and the long term." (MIT Energy Initiative 2016, p236).

For instance, this is already the case between the north and the south of Germany as presented in Figure 5. But also, unprecedented coordination challenges are expanding towards the local scale at a fast pace (Lavoine 2018). As depicted in Figure 4, the distribution networks are particularly concerned with further locational issues since they will face "reversal flows, congestion and localized voltage and protection issues" (EPRI 2016, p28).

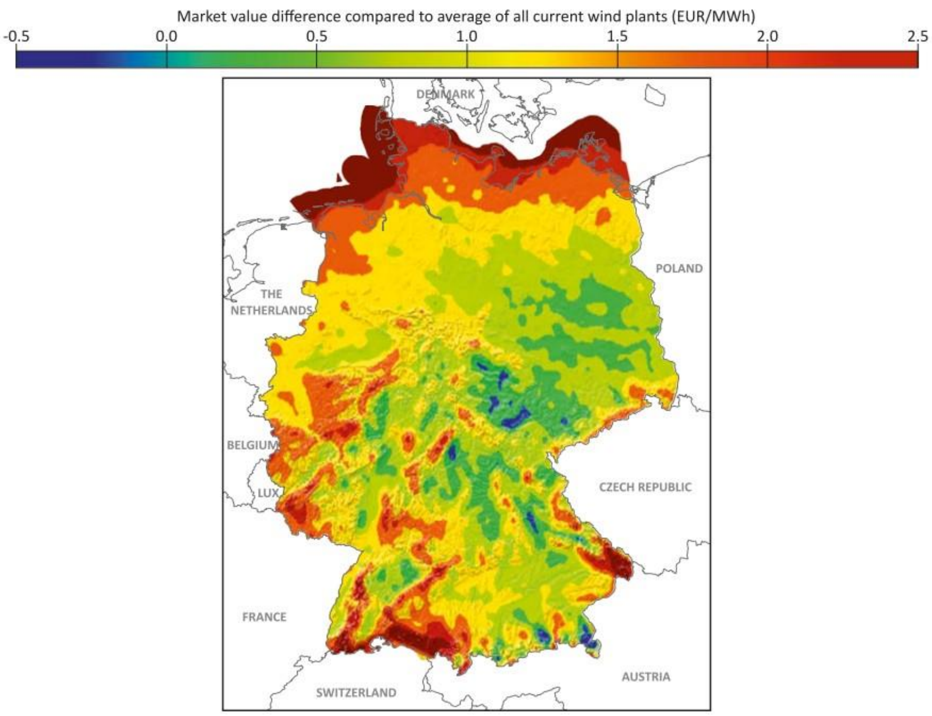

Figure 5. Map of the market value of wind energy in Germany. Source: (IEA 2017a)**, adapted from https://marktwertatlas.de/de/marktwertatlas**

By 2050, most of the EU generation capacity is expected to be placed at the distribution network, moreover, ICT, smart appliances and new energy usages such as the adoption of

[52] Recent efforts from EPRI has come up with high level guidelines for representing DER on transmission capacity expansion studies. Further information is available at:

https://www.epri.com/#/pages/product/000000003002010932/?lang=en-US&lang=en-US ; and

https://www.epri.com/#/pages/product/000000003002013503/?lang=en-US electric mobility, would allow a more active role of the assets connected at distribution level, both, in front or behind-the-meter, entailing significant increases of distribution network utilisation[53]. Still, significative flexible capabilities can be harnessed at the distribution and local levels (i.e. demand response, storage, electric vehicles providing services to the grid), but currently only limited monitoring and control devices are deployed at mid and low voltage levels, and no price signals or market mechanisms are been implemented to provide market-based coordination.

Considering that distribution grids are generally radial but balancing requires looped grids, “balancing operations at local distribution loops will only be valid if the distribution grids manage parts of the high voltage networks (at least up to 110/130 kV), which is not yet the case in all European Union countries” (Lavoine 2018, p3). This opens the question of market design to a deeper level, which bring us back to the “structure-architecture-rules” fundamentals. Recent research proposes alternative views on these issues:

1. Extending the locational marginal pricing (LMP) to the distribution level is been pioneered by Caramanis and collaborators (Ntakou and Caramanis 2014; Michael Caramanis et al. 2016; Babonneau, Caramanis, and Haurie 2016, 2017; Michael Caramanis et al. 2017).

2. The creation of local energy market at the distribution level is been studied in (Cardell 2007; Ampatzis, Nguyen, and Kling 2014; Teotia and Bhakar 2016; Ramos et al. 2016; Teotia et al. 2017; Holtschulte et al. 2017; ENA and CSIRO 2017).

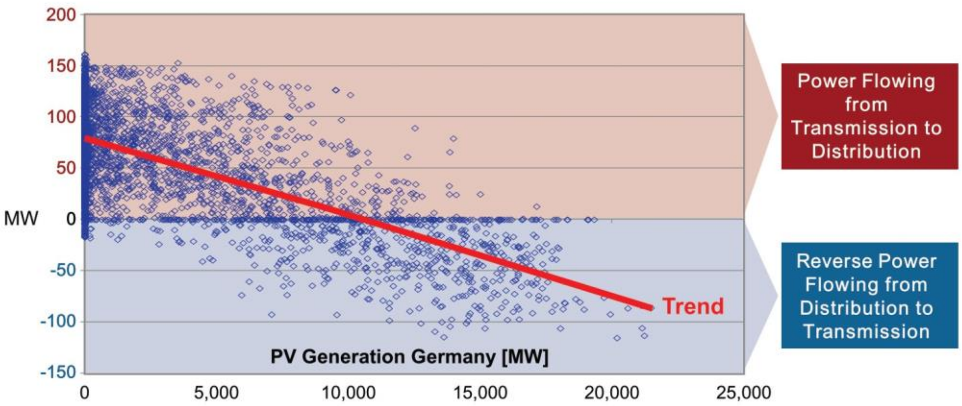

Figure 6. Trends of power flow directions on T&D lines. Source: (EPRI 2016)

Hence, regulatory frameworks are also challenged. The upsurge of the active role of DSOs for handling variability and flows, and the enhanced TSO/DSO coordination for optimizing services at multiple voltage levels are some examples (Gerard, Rivero Puente, and Six 2018). Also, grid charges need to evolve for ensuring the recovery of costs of regulated assets while providing enough incentives for addressing coordination of behind-the-meter assets and DER (Ruester et al. 2014; Burger, Jenkins, and Batlle 2018), and data management protocols. Some interesting cases of new business models, market design and regulation at the

[53] As for CSIRO (2016), network utilisation is the ratio of energy supplied to the maximum energy that could have been supplied by the network capacity.

distribution level are commented in (Ardani et al. 2018; Cook et al. 2018; Ma and Cheung 2016; Pereira et al. 2018).

Taking the rise of the local scale to its limits, recent developments of distributed ledger technologies (DLT), such as blockchain, might pave the way towards a “transactive energy”[54] future opening trading possibilities to peer-to-peer (P2P) and/or peer-to-system[55] (P2S) exchanges at the very local level, where no retailer, market provider or any other intermediary would be required (Taft 2016; Eid et al. 2016; Park and Yong 2017; Lüth et al. 2018; Mengelkamp et al. 2018a, 2018b; Sousa et al. 2019).

Furthermore, more than two decades ago Stern (1992) analysed the adoption of energy conservation programs from a psychologist viewpoint. He highlights that non-economic motives are also important for shaping energy uses and technology choices at the consumer level (i.e. residential). Experience also shows that other than direct cost, consumer preferences and personal values and attitudes matter (Boughen, Castro, and Ashworth 2013; CSIRO 2013). Considering the increasing trend towards multi-sided trading platforms enhanced by information and communication technologies (ICT), user-level preferences might lead to heterogeneities on the demand-side. Attributes such as origins, valuation of environmental footprint, self-sufficiency or appealing for autarky, preference for local generation, among others, might further complexify the traditional market coordination problems.

As it has been discussed, the shift towards a low carbon electricity sector introduces new challenges to system operations and market design. They could be presented as old days problems expanding on their scope and scale, so blurring the boundaries between the local and global scales, between consumers and generators as well, while simultaneously requiring higher refinement on the temporal and spatial dimensions. This vision completes the recommendations of key studies on system planning by introducing a perspective for market design consistent with the idea of focusing on system costs instead of integration costs (Keppler and Cometto 2012; Holttinen 2016; IEA 2017b, 2018; Cometto and Keppler 2019), comprising the existence of external economies within the electricity sector, but also supporting a broader framework aiming to move to move the discussion towards ‘’full costs”, so linking environmental externalities with social welfare (Keppler et al. 2018).

5 Market designs for the future

Some nomenclature deserves to be introduced at this point. In the sense of this study, market types correspond to the general setting of the market defining what is to be exchanged. Thus, each market proposal is a market type. Every market type contains a market architecture composed by different market segments[56] and their linkages. Variations of the market architectures would modify linkages, so defining new market types. Following Stoft (2002c),

[54] Further information on this point is presented in appendix 8.1.

[55] Often denoted to peer-to-market (P2M) even if the principle implies that there is no tangible market intermediary but a platform.

[56] Market segments use to be referred as markets themselves in the literature. In the sense of this report they are considered as “submarkets”. Nevertheless, it can be seen that it is only a relative distinction.

market linkages might be "implicit price relationships caused by price arbitrage" and expectations, or "explicit rules linking rights purchased in one market to activity in another" that can be enforced by incentives or penalties. In this report, market types are listed with numbers while market's segments are listed with letters.

Furthermore, following the classification used by Zinaman et al. (2015) on their categorization of power systems of the future, we adapt the classes of Hope Hailey and Balogun (2002) to provide a reading grid for our market design proposals.

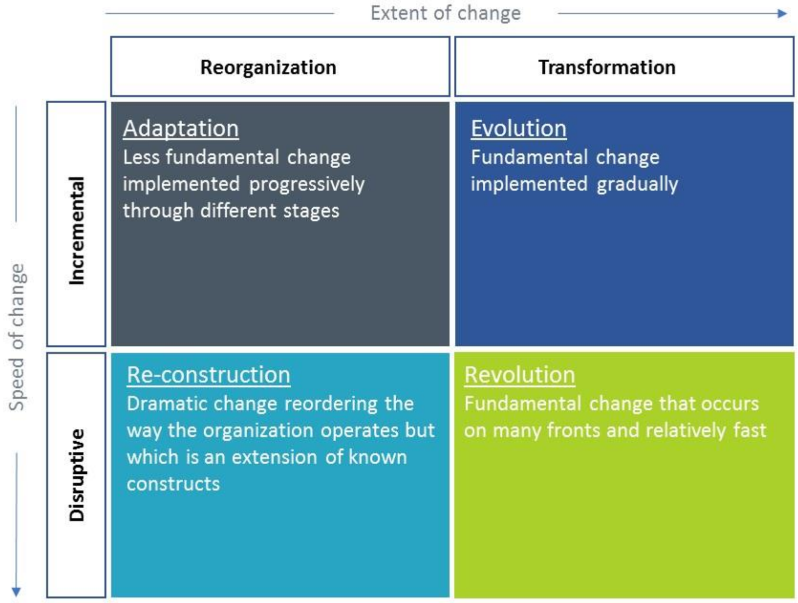

Figure 7 sketches the proposed categories. According to Zinaman et al.:

> "*Typically, power systems are in the "Adaptation" mode, accommodating incremental changes in demand growth, technology change, and consumer preference. (…) "Evolution" implies fundamental changes to power system technologies and actors, albeit over a relatively long period of time and through sustained incremental change. "Reconstruction" implies rapid change, but without fundamental changes in power system actors or technologies. For example, introductions of new institutional structures, such as competitive wholesale power markets, with limited change in the generation fleet, tariff structure, or customer interactions. "Revolution" implies rapid fundamental changes across power systems and might incorporate full competitive markets, services, and real-time rates. How, and at what speed, will power system transformation unfold? The options can be conceived of as a range of pathways in the landscape, from adaptation (slow but not fundamental), reconstruction (fast but not fundamental), evolution (fundamental and slow), to revolution (fundamental and fast).*" (Zinaman et al. 2015, p.10)

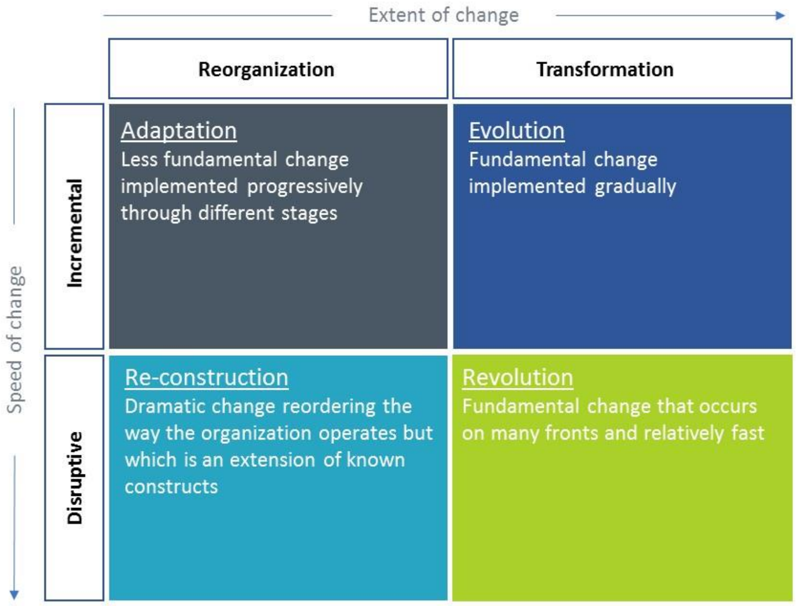

Figure 7. Types of market designs. Source: (Zinaman et al. 2015), originally adapted from (Hailey and Balogun 2002)

5.1 Objectives, principles and market architectures

Any market design starts by defining clear objectives. Following Stoft (2002c) and Cramton (2015), we propose the following three objectives:

- Economic efficiency:
    - Short-run efficiency[57]: meaning that demand is satisfied at least cost given existing resources.
    - Long-run efficiency[58]: meaning that the ideal quantity and type of resources are provided to meet economic electricity demand at least cost.

- Simplicity and transparency: according to the easiness, clarity and unambiguousness of rules, allowing to that map bids into outcomes, and incentivize truthfulness. Simplicity and transparency of design are great virtues, not so much because of the direct cost of operating under complex designs, which can be substantial, but because of the flaws complex designs conceal (Stoft 2002c).

- Fairness: non-discrimination among market participants or technologies.

In theory, under perfect market conditions marginal pricing is the best solution for ensuring economic efficiency on operation and investments. Under such conditions, marginal prices allow optimal dispatch decisions, and if prices can attain the true value of rationing (i.e. value

[57] Following the semantics of economic theory, the short-run efficiency corresponds to the concept of productive efficiency.

[58] Similarly, the long-run efficiency corresponds to the concept of allocative efficiency.

of lost load or VOLL) during periods of scarcity, the technologies on the optimal mix would recover its fixed cost over their lifetime (Green 2000). In practice, such level of competitivity is difficult to obtain due to the short-term inelasticity of demand impeding the application of a true VOLL and conducing to administratively set reliability standards with regulated price caps. The introduction of pecuniary externalities due to near-zero power generation units only worsen the picture. The advocates of energy-only markets claim that a sufficient solution would be to ensure competition and improve scarcity pricing. Nevertheless, other analyst only partially supports this view as it improves coordination issues in the very long-run, considering it insufficient for real conjunctural risk of under supply that need to be handled quickly to avoid costly reliability issues, and/or due to problems of missing markets. Many electricity market have introduced explicit capacity remuneration mechanisms (CRM) for completing the revenue sufficiency required to attain resource adequacy in the long-run (Botterud and Auer 2018).

Cramton (2017) also recognizes that “the best market designs for the future will continue to rely on a highly efficient spot market with strong support for forward contracting, as well as a competitive retail market to foster innovative demand response. This core framework is best apt to support efficient long-run investment” (…) “A stable and coherent climate policy based on a carbon price would further support this goal by greatly reducing investment uncertainty” (Cramton 2017). Hence, including intraday or real-time markets, and a short-term market (e.g. day-ahead) for forward contracting appears essential in any attempt of market design. Reinforcing and improving these market segments are at the core of our market design proposals.

Based on the previously presented objectives, and on the ongoing debate about the sufficiency of energy-only markets to deliver long-run efficiency, our approach to market design follows a diagnose and prescription logic with two stages:

i. Short-run diagnose: The first stage consists on designing and simulating enhanced energy-only markets on the relevant scenario. By this mean we can quantitatively evaluate short-run efficiency.
ii. Long-run diagnose: In the second stage we proceed to assess the extent every proposal performs in term of long-run efficiency, and fit-for-purpose other compensatory solutions when required.

By following this logic, we will quantitatively assess the performance of every market design along the two dimensions of economic efficiency and would properly prescribe corrective issues (e.g. CRM[59]) as well as other kind of alternatives if needed[60] (long-term contracts, exploitation licenses, among others).

Recently, Conejo and Sioshansi (2018) further developed these principles and highlighted some of the challenges at this particular point of time, in which, the industrial landscape of

[59] (E. Ela et al. 2016; Botterud and Auer 2018) provide some CRM prescriptions on this regard.

[60] An interesting, and rather innovative, proposal of market design is to consider “competition for the market” rather than “competition in the market”. A comprehensive “straw man” proposal on this line is available in the appendix.

power systems is being disrupted but we can still “rely on lessons learned from the past three decades of market-restructuring experience”. They affirm that electricity markets are reaching a “breaking point” because current market designs were conceived to operate with dispatchable, predictable and centralized generation, and despite that relevant market reforms have been introduced in the last decades, they are not well-suited to handle future power system operations. Shah et al. (2016), and Newbery et al. (2018) also provide principles and takeaways for designing clean energy markets on this sense. They outline the following six principles for re-designing future electricity markets:

1. Including multiple successive trading auctions: So, setting a favourable framework to deal with imperfect information, increasing uncertainty and to allow risk hedging.
2. Including a precise representation of the physical layer: for avoiding inefficiencies related to poor pricing, cross subsidies and incentives issues.
3. Decreasing uncertainty representation as energy delivery approaches
4. Co-optimization of energy and reserves
5. Clearly defining private property rights
6. Demand-side participation and the role of the “utility”: this implies a pro-active role of consumers and redefining the role of the “traditional” utility.

5.2 Strategy: Scenario-specific market design proposals

As affirmed by Stoft (2002c)[61], it is prudent to say that “testing is the key to successful design”, “but since rigorous testing, though worthwhile, is expensive so a simple "bottom-line" test should always be conducted first”. He’s bottom-line test goes straight forward by:

> *“(1) model the market with and without the design in enough detail to compute the design's impact on production costs, (2) find the minimum possible cost of delivered power, and (3) find the cost of delivered power when the market operates under the proposed rules. If the design raises costs significantly, it fails the test. Such a test cannot prove that the design will work well in the real world, but it often shows it will fail under even ideal conditions, a useful, if disappointing, result.”* (Stoft 2002c) p.94.

Hogan (2018)[62] claims that “no design can be perfect, but the record indicates the high costs of ignoring first principles”. He opposes two possible perspectives about designing electricity markets by introducing the following statements regarding to market design: on one side, “the Perfect is the Enemy of the Good?”, on the other “Good Enough is Neither Good Nor Enough”. In that way, he emphasises the importance of procuring “better than good enough” designs

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[61] He continues by claiming: ”testing is the key to successful design is well understood by engineers until they design markets instead of equipment. It is not well understood by policy makers or economists, and the results are predictable.” (Stoft 2002c)

[62] From his talk on market design at the IAEE conference in Groningen on June 2018.

when the issues at the stake are “so affected with the public interest”. He follows, “When “good enough” is good enough, the costs of the unintended consequences can be high.”

The arguments of both authors rise two key questions regarding the task of WP2: the first question is the well-known problem of trade-off when modelling any complex system. It is necessary to arbitrate between the level of detail desired to represent the aftermaths between market products and market parties, against the resources at hand (i.e. computational capability, time, etc). The second is a subtler question and deals with the imperative to have a comparable benchmark for being able to assess the performance of the proposed design.

As presented in section 3.2, three scenarios are considered in OSMOSE defining possible states of the world by 2030 and 2050. Such scenarios are complete states, thus, entirely define the set of hypotheses in every case. Given the highly contrasted possibilities embodied in every scenario, market architectures should accommodate these divergences.

Hence, the market design proposals of OSMOSE are to be confronted with different sets of hypotheses affecting the temporal and spatial coordination in relation to every scenario. Since we expect that every market proposal would perform properly only on limited range of conditions, we follow a scenario-based design, but proceed to map similar market design proposals to other scenarios for cross comparisons[63]. The benchmarks to assess performance will be based on the outputs of WP1, who adopts a social planner perspective[64]. We recommend several key performance indicators (KPI) to quantify the performance of every proposal[65]. Accordingly, the strategy is to stay result-oriented and to be aligned with a neutral and analytical vision.

5.3 Modelling market designs and implications for choice of market design choices

Since the liberalization of energy markets and introduction of competition the regulatory and market design has been subject to ongoing changes. To improve efficiency, the focus was mainly on improving the coordination between real-time services (e.g. provision of balancing, reserve and stability services) and long-term needs (i.e. maintenance of generation and network adequacy) in the past two decades. Moreover, coming from a centralized power system the further development of power markets mainly focused on the large-scale

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[63] The drawback of this vision is that limited cross comparisons could be done on market designs corresponding to different states-of-the world. A possible key to overcome this issue would be to use ex-post feedback from outcomes to settle “invariant parts” of the market that would correspond to “future-proof market segments” if any. Other more ambitious, but risky, possibility would be to directly propose a “future-proof market design” by introducing overlapping submarkets that becomes neutral in any or other state of the world. The latter would be plagued with significant complexity to conceal ambiguity of inputs. Implementing those strategies are out of the scope of the project but might be the subject of further research.

[64] In economics, it is used that the results of the social planner are equivalent to those of a perfect market.

[65] A comprehensive report proposing different key performance indicators was elaborated by the WP2 and is available on demand.

perspective (cross-country exchanges). In contrast, the ongoing integration of small-scale renewable generation (i.e. wind and photovoltaics) and flexibilities results in a more and more decentralized power system, which is why in today's power markets locational coordination is becoming increasingly important also in view of limiting the need for additional transmission and distribution capacity.

The ongoing debate on improving electricity markets points at three main challenges. First, market failures cause long-run inefficiencies in current energy-only markets. Besides price caps in energy markets and the missing money problem (i.e. long-run fixed costs of assets cannot be covered by revenues from the energy markets) also missing locational signals constitute a market externality resulting in inefficient investment or decommissioning decisions. Second, the increasing uncertainty mainly due to the expansion of variable renewable energy sources leads, "ceteris paribus", to a need for higher reliability margins for real-time operation (i.e. stability and security). Third, the decentralized organization of system and market operations throughout Europe (in contrast to systems with central dispatch) introduces technical challenges at the transmission as well as the distribution grid level.

Against this background the integration of flexibilities will create new opportunities, when it comes to an improvement of the spatial coordination expanding towards the local scale. These new opportunities should be supported by the regulatory and market design as further detailed in the following.

5.3.1 Key aspects of a market design for the future

When it comes to designing future power markets, the European framework provides a common basis for potential adaptions and evolutions. Consequently, the European Internal Electricity Market is assumed to be achieved, meaning that the zonal flow-based market coupling is in place with standard products and homogeneous rules as stipulated by the latest European regulations.

The increasing shares of variable renewable energy sources, i.e. wind and solar, will lead to a higher volatility in power systems and congestions more variable over time and space. In this context, the integration of market and grid operation raises the question of how much temporal and spatial granularity would be required, to fine tune market coordination and efficient pricing. Further relevant questions concern the valuation of flexibility at the interface between regulated and market-based services, e.g. co-optimization of energy and reserves (and stability services). Moreover, in new emerging markets peer-to-peer (P2P) trading may play a role. Forming a link to the work performed under WP1 it should be questioned after "getting the prices right" on short-term markets, if the prices would send sufficient investment signals and manage the risk allocation efficiently.

Against this background the basic market design proposals are based on two key aspects, namely the **temporal coordination** with a focus on the short-term and real-time timeframes and **spatial coordination** covering zonal and nodal market designs (cf. Figure 8).

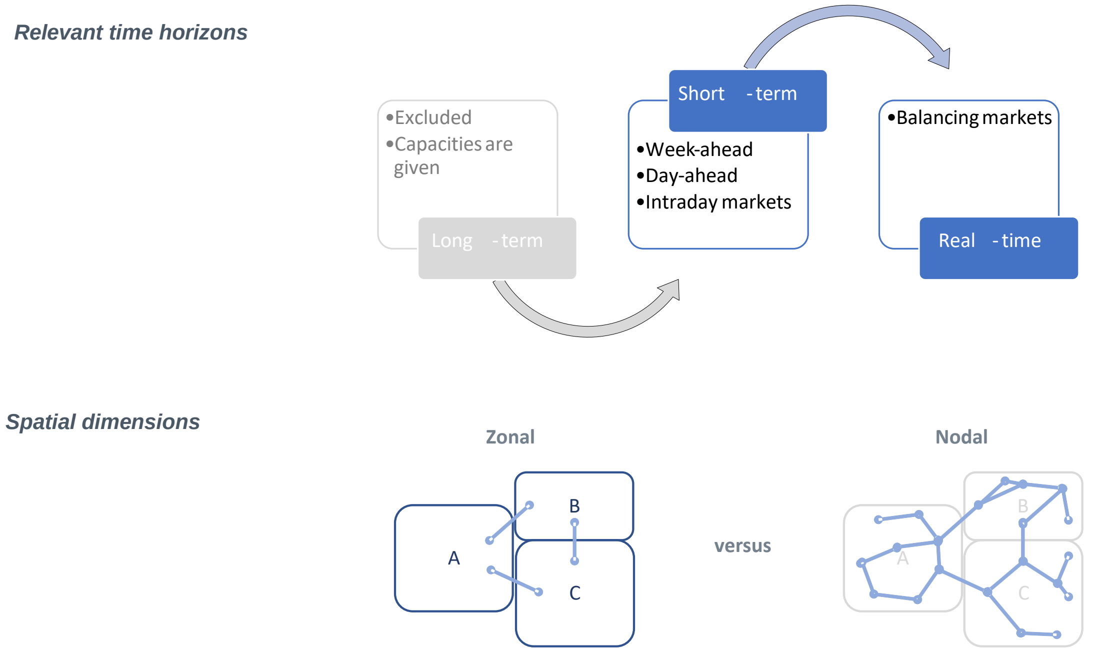

Figure 8. Key aspects of market design

As shown in Figure 8 the following market designs will cover week-ahead to Intraday markets as well as balancing markets and assume installed generation capacities as given. To guarantee a consistent framework, it is intended to align the scenarios and results with the long-term market equilibria determined under WP1. Consequently, the work in this work package will in a first step focus on "Getting the prices right" on short-term markets and in a second step analyze fit-for-purpose long-term markets in order to close potential capacity and financial adequacy gaps.

5.3.2 Reference Market-Designs

Driven by the increasing spatial granularity, two basic market design proposals are foreseen and described in the following:

1. Power exchange with zonal pricing
2. Power pool with nodal pricing

Power exchange with zonal pricing – MD1a

This market design is mainly based on the target model as foreseen in the regulations stipulated by the European Commission[66]. Basically, national power markets are coupled via the single day-ahead and intraday market coupling under a zonal pricing scheme. The power exchanges are responsible for operating the market clearing algorithm using commercial transaction constraints provided by TSOs and demand and supply offers submitted by market

[66] The target model is outlined in Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity and is further specified in the corresponding regulations (based on the network codes drafted by ENTSO-E) covering rules for connection, operations and markets.

participants as inputs. Moreover, balancing markets with common principles for the procurement, activation and the settlement of balancing services are implemented as stipulated by the Electricity Balancing Guideline[67].

Based on the current target model moving a few steps further this zonal market design entails some major additional or new elements:

- **Higher temporal resolution**: currently cross-zonal electricity markets are based on hourly products in Europe, while in some Member States higher granularities, e.g. 15 minutes products, have been implemented in recent years. Hence to keep pace with the increasing variability due to renewable energy sources, cross-zonal day-ahead and intraday markets with a higher product granularity as today are foreseen, e.g. adapting from hourly to at least 30 minutes products.
- **Shorter lead times**: in the same way, the granularity for procurement and scheduling ancillary services is increased from monthly or weekly to day-ahead procurement. This enhancement is in line with the principles as stipulated by the Electricity Balancing Guideline requiring that the "procurement process shall be performed on a short-term basis". Moreover, enhanced product definitions can be tested, e.g. including faster activation times, asymmetric products for reserves and a higher granularity of reserve qualities.
- **Flexibility products**: the further expansion of intermittent renewable energy sources (and possibly also new electricity uses) will lead to higher gradients of the residual load (i.e. total system load minus renewables infeed) which in turn will increase the operational ramping needs. Following the U.S. markets, forward contracts for 5-10 minutes ramp capability products to maintain dispatchable flexibility might be considered.
- **Congestion management**: capacity allocation in zonal electricity markets entails the translation of physical into commercial transaction constraints. Due to immanent simplifications of zonal markets and discrepancies between forecast and realized conditions due to uncertainties, resulting commercial schedules might not be physically feasible, hence requiring corrective measures, i.e. remedial actions, by TSOs. Today TSOs consider so-called non-costly remedial actions, e.g. topological measures or change of tap positions of phase-shifting transformers, during the capacity calculation timeframe to optimize the capacity domain given to the market. Costly remedial actions are considered at the last time to decide for preventive measures and during real time for corrective measures in accordance with the risk policy of the TSO. Consequently, the consideration of remedial actions like re-dispatching during the capacity calculation, allocation and post-allocation timeframes, i.e. in the flow-based market coupling algorithm, might be analyzed.
- **Improved coordination on re-dispatching**: one of the main targets of the European guidelines and the Clean Energy Package is the further harmonization of congestion management principles across Europe. Regarding coordinated re-dispatching

[67] For more details see: Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

measures, today there exist mainly bilateral agreements between TSOs leading to an imperfect cross-border cooperation. Improved coordination will address this flaw and explore an expansion of the geographical coverage.

- **Integration of energy and reserves**: in today's framework reserves and energy are cleared on a sequential basis. In most European countries reserve auctions take place before the clearing of day-ahead energy markets leading to opportunity cost bidding for reserves. Potential inefficiencies due to dynamic and uncertain system conditions might be overcome by simultaneous pricing of reserves and energy. Hence, for the day-ahead and intraday market enhancements can be introduced by co-optimization of energy and reserves. This will however imply challenges regarding the integration into the market clearing algorithm EUPHEMIA and the retention of portfolio bidding in current short-term markets.

Power pool with nodal pricing – MD2a

In view of today's zonal market design, the power pool with nodal pricing can be seen as another way to handle congestion. Following the power markets in the United States, this market design entails a day-ahead market with hourly locational marginal prices for the next day and a real-time market in which current prices are calculated at five-minute intervals based on actual grid operating conditions. Locational marginal prices are determined by the so-called Independent System Operator (ISO) within a centralized optimization maximizing welfare subject to constraints.

This market design involves some fundamental changes, namely the full integration of capacity allocation and market clearing and the central optimization including constraints regarding unit commitment, dispatch and grid operations. The latter aspect is moreover accompanied by an adjustment of the institutional framework moving from a decentralized market organization with several TSOs and power exchanges across Europe to a centralized one with the ISO responsible for both grid and market operations.

Further main features and potential enhancements compared to existing nodal markets are the following elements:

- **Co-optimization of energy and reserves**: selecting the right resources for right products at the right time and the right price is one of the key challenges in electricity market design. While also considered under the zonal market design as a potential enhancement, the co-optimization of energy and reserves on a day-ahead market through a security constrained unit commitment with local marginal prices is a common feature of existing nodal markets.
- **New reserve qualities**: to dispatch faster, dynamic resources like battery storages new types of reserves are considered. Following the PJM design an energy-neutral fast reserve product (e.g. RegD) separately from other "traditional" types could be introduced. Thereby, energy neutral means that the amount of upward regulation provided by a resource would match the amount of downward regulation provided by the same resource, converging to neutrality within the considered scheduling interval, e.g. 15 minutes.

- **Enhanced forward markets**: Possible enhancements for the short-term markets are a forward contract for asymmetric 10 min (or lower) flexibility ramp products (up and down) co-optimized with energy and reserves based on implicit opportunity cost (like CAISO) as well as the consideration of nodal Financial Transmission Rights (Week-ahead).
- **Real-time co-optimization**: For the real time, possible enhancements are energy and reserve co-optimization through a Security Constrained Economic Dispatch with Locational Marginal Prices (LMP) and a reserve activation with an enhanced attribution mechanism allocating balancing and congestion cost.

Under both the zonal and nodal market design interest should be put on the flexibilization of the demand side. While both proposals focus on the wholesale level and potential enhancements of the underlying market designs, enabling flexibility also requires a consideration of the retail level and end consumers. So far mainly industrial consumers provide flexibility in electricity markets and the large-scale integration of commercial and residential consumers is still in its infancy. One way to foster the utilization of demand side flexibility is the introduction of real-time electricity prices or retail tariffs reflecting the actual value of flexibility for the electricity system. Hence, depending on the considered time horizon real-time pricing might be accessible for commercial and residential consumers leading to partial elastic electricity demand. Against this background, time-dependent shallow (or deep) network access tariffs for behind-the-meter flexibility might be implemented and further studied.

In case flexibility is provided by commercial and residential consumers, load aggregation is considered as key aspect to stimulate the bottom-up contribution of end-users[68]. The aggregation of loads requires access to spatially distributed entities, consequently interacting with the underlying congestion management scheme, i.e. zonal or nodal pricing. This is not only true for aggregated loads but also for distributed generation sources, e.g. small-scale biomass plants or wind parks, aggregated into virtual power plants (VPP).

While under zonal markets internal congestions are ignored facilitating the aggregation of distributed resources within a zone, under nodal markets theoretically physical transmission constraints between different locations must be considered potentially limiting the aggregation in case of congestion. There might be different ways to address this challenge under nodal markets, e.g. introduction of virtual resources and bids with corresponding nodal generation distribution factors or the definition of virtual hubs aggregation several nodes. Consequently, the further analysis will explore options to allow third parties, such as aggregators and VPP to serve as brokers to give market access to distributed resources.

5.3.3 Variations of market designs and scenario allocation

Based on the two reference market designs (Power exchange with zonal pricing – MD1a and Power pool with nodal pricing – MD2a) different variations are foreseen.

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[68] See e.g. C. Eid, P. Codani, Y. Chen, Y. Perez and R. Hakvoort, "Aggregation of demand side flexibility in a smart grid: A review for European market design," 2015 12th International Conference on the European Energy Market (EEM), Lisbon, 2015, pp. 1-5. doi: 10.1109/EEM.2015.7216712

First variations are defined to foster the valuation of flexibility at the distribution grid level:

Local flexibility markets – MD1b

The variation MD1b extends the model "Power exchange with zonal pricing – MD1a" with local flexibility markets at the distribution level. Following the ENERA approach, this variation will introduce order books at a local level with anonymized orders allowing TSOs and DSOs to procure local flexibility for system services like re-dispatching.

LMPs at distribution level – MD2c

Under the power pool with nodal pricing (MD2a) the focus is on LMPs at the transmission level down to 220 kV to efficiently allocate scarce transmission capacity. Variation MD2c extends the model MD2a to the distribution level, to enhance distributed flexibility valuation.

With the increasing share of distributed small-scale renewable energy sources and emerging role of prosumers alternative transaction mechanisms are gaining importance. Mainly at the local level so-called peer-to-peer (P2P) energy transactions provide prosumers with the opportunity to trade energy among each other. With the TSO or DSO acting as consumer also system services might be procured using such transactive approaches.

Consequently, variations with a focus on peer-to-peer (P2P) transactions are defined:

Transactive energy market – MD1d/ MD2d

The transactive energy market includes peer-to-system (P2S, sometimes also called P2M with the market being handled by the system operator) for balancing and other ancillary services.

In the short-term, this means energy and balancing/Ancillary Services market includes P2S exchanges.

A balancing market with P2P with the TSO as the "insurer of last resort" allows to ensure sufficient levels of reliability in a price discriminative way.

In the academic literature and energy policy there is an ongoing discussion about market design and maintaining resource adequacy, i.e. sufficient available generation capacity to supply the electrical load. Capacity mechanisms provide incentives to maintain plants or invest in new generation facilities in reducing the missing money problem through capacity payments. In contrast, Hogan (2005) proposes another option based on an energy-only market with the demand for operating reserves leading to high prices in scarcity situations. Consequently, the implementation of an Operating Reserve Demand Curve (ORDC) mechanism could be considered as a further enhancement.

While the reference market designs are considered for each of the three scenarios defined within WP1, the variations are related to single scenarios.

Short digression on scenarios:

As previously introduced in section 3.2, *three scenarios are distinguished: the "Current goals achieved" (CGA), the "Accelerated transformation" (AT) and "Neglected climate action" (NCA).*

The following figure illustrates the key elements of the different scenarios with regard to the simulation tasks in WP1 as well as in WP2. Key differences are the emission levels for 2030 and 2050, final energy demand, for both, the heat and the power sector as well as the available technologies, in particular coal. Between the NCA, CGA and AT a clear trend can be seen in each of the key elements.

	Neglected climate action (NCA)	Current goals achieved (CGA)	Accelerated transformation (AT)
Emission levels ▪ 2030 and 2050	• No global fulfilment of NDCs • Europe fail to attain CO2 reduction targets by **5% in 2035 and 10% in 2050. Thus, offsetting only 35% until 2030 and 70% until 2050.**	• Global fulfilment of NDCs • Achieving **40% of CO2 reduction by 2030** and **80% reduction by 2050** in Europe	• Achievement of **1.5°C target** • Europe achieves **55% and 98% CO2 offsets by 2030 and 2050** respectively • Very high shares of renewables are attained
Final energy demand (heat and power sector)	• Slight overall increase	• Constant final demand for electricity ad high temperature heat. • Demand for low temperature heat decreases by 20%	• Moderate efficiency gains in electricity and high temperature heat. • Demand for low temperature heat decreases by 25%
Technologies	• Coal phase-out until 2045	• Coal phase-out until 2040	• Coal phase-out until 2035

Figure 9: Key elements of the scenarios (cf. WP1)

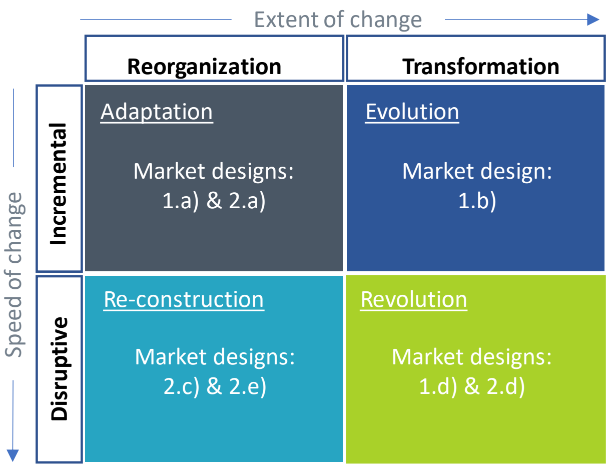

Figure 10: Type of market design

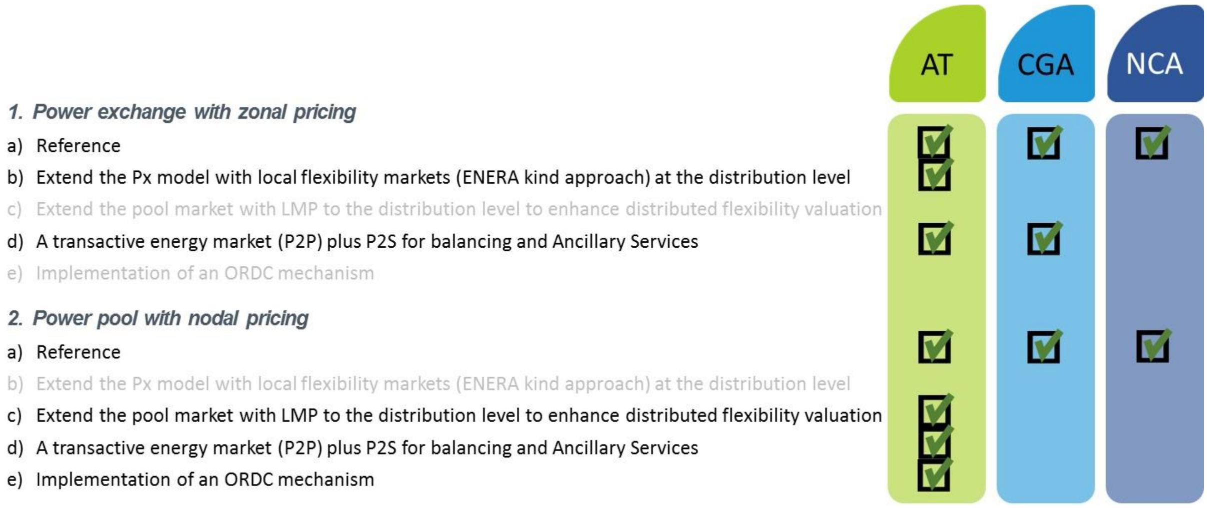

Figure 11: Allocation of market designs to scenarios – Overview

6 Conclusion

After almost three decades of restructuring electricity markets, extensive knowledge and experience have been cumulated on market and regulation design. Nevertheless, the ever-evolving structure of power systems, together with the uptake of environmental concerns and climate policies, have been constantly introducing new challenges and forcing market designs to evolve in different waves.

Given the disruptive technological changes implied by the goals of deeply decarbonizing power systems on the years to come, the question of market and regulation design is back on the spotlight and seems as relevant as it was during the early days of power system restructuring.

The topic is experiencing effervescence among researchers and practitioners. Multiple kinds of proposals with different degrees of refinement can be found in the literature. They co-exist but are not necessarily comparable. Particularly those that are workable with those which are only strawman propositions. Nevertheless, as on the early days of restructuring, every design started being only a theoretical proposal, so every one of them deserve consideration if founded on sound economic principles.

Analyst only agree on the fact that current market designs are ill-suited to take the decarbonization challenge, so coinciding on the fact that a profound revision urges. From current discussions, only market failures can be depicted, and principles of design can be highlighted.

Given that no market design can be perfect and flawed designs can be very costly, any market design proposal should be built on sound principles, carefully designed and prudently tested. Moreover, the economic performance of any market design depends on the organizational structure in place which is evolving by nature, particularly on a sector under transition. Thus, it would be prudent to avoid any intent of proposing one-size-fit-all design. Instead, following a fit-for-purpose approach appears to be better suited.

This report built a bridge between the fundamentals of market design and the recent studies on the topic by discussing the main market failures of current market designs, prospecting the challenges for the years to come, and identifying sound principles to propose alternatives of improvement. It aims to define a strategy and provide a methodology for testing and ranking market design proposals. Different market designs have been proposed which are then mapped to the scenarios considered in the project. Variations of such proposals have been also considered. The common thread among them is the simultaneous consideration of integration of non-conventional renewable energies, the will to harness cost-effective flexibility from every possible source, and the offsetting of the resulting carbon footprint. In practice, the challenges are traduced by exacerbated spatial and temporal coordination requirements, but also comprising the question of full costs, so including environmental externalities. Coordination requirements are intrinsic to the hypotheses considered on every scenario, thus, it can be expected that every market design and its variations would perform well only on a limited range of conditions. Hence, they should be compared in terms of KPIs. This is only the start of the journey, the next steps would be to model, simulate and compare the proposals to portray comprehensive recommendations and intend specific conclusions on this subject.

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8 Appendix

8.1 Ambiguities and uncertainties of a transactive energy future

The applications of distributed ledger technologies (DLT) on the energy sector are on their early stage of development. They have the potential to completely revolutionize the entire market and regulation design of electricity market. Nevertheless, together with distributed energy sources (DER), their adoption and pace of development is unknown. Analyst comment:

"The main question we see is whether this integration and coordination function will be carried out primarily by utilities through regulated investment in DER management systems (DERMS) that will allow them to reach into customers' homes and businesses and directly manage and optimize DER utilization, or whether it will be carried out primarily through competitive DER providers and optimizers, who will respond to signals reflecting long-run and short-run needs of the distribution system as a secondary priority, after the primary one of optimizing the value their customers receive from the DERs installed in their homes and businesses. Similarly, we see a variety of ways DER ownership could itself evolve—from a purely competitive market (whether traditional or through a new "sharing economy" approach), to a largely utility-supported set of investments, much as some energy efficiency and demand response assets are supported by utilities today." (Steve Corneli, Kihm, and Schwartz 2015)

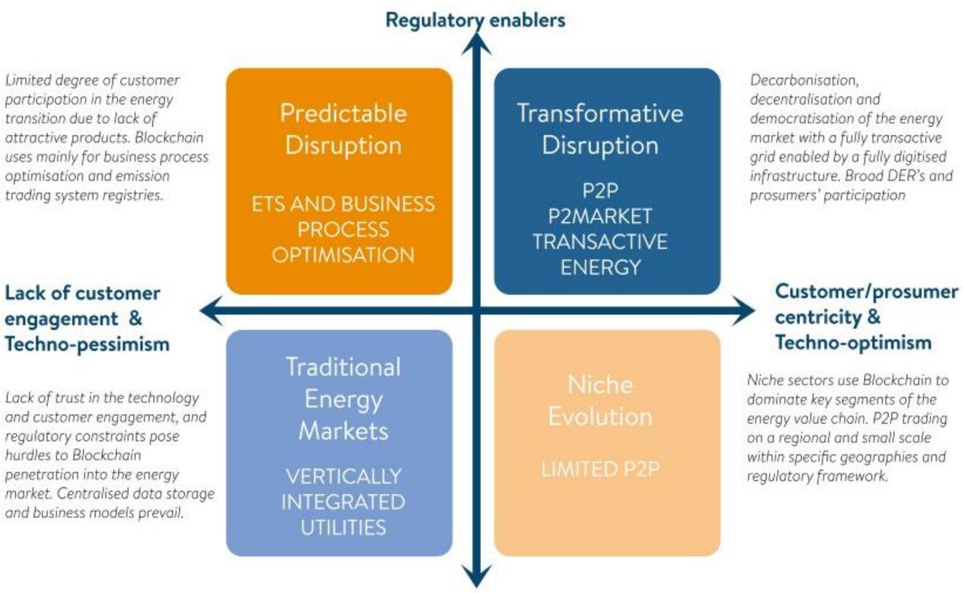

Figure 12. Blockchain in the energy sector (WEC, 2018)[69].

[69] Further information on the potential applications of DLT on the energy sector is available at: https://www.worldenergy.org/wp-content/uploads/2018/10/World-Energy-Insights-Blockchain-Insights-Brief.pdf

8.2 Technological solutions of OSMOSE demonstrators

A comprehensive description of technologies being developed by OSMOSE demonstrators can be consulted on the internal companion report on the subject. Figure 13 presents the main findings regarding market synergies and market barriers identified on that report.

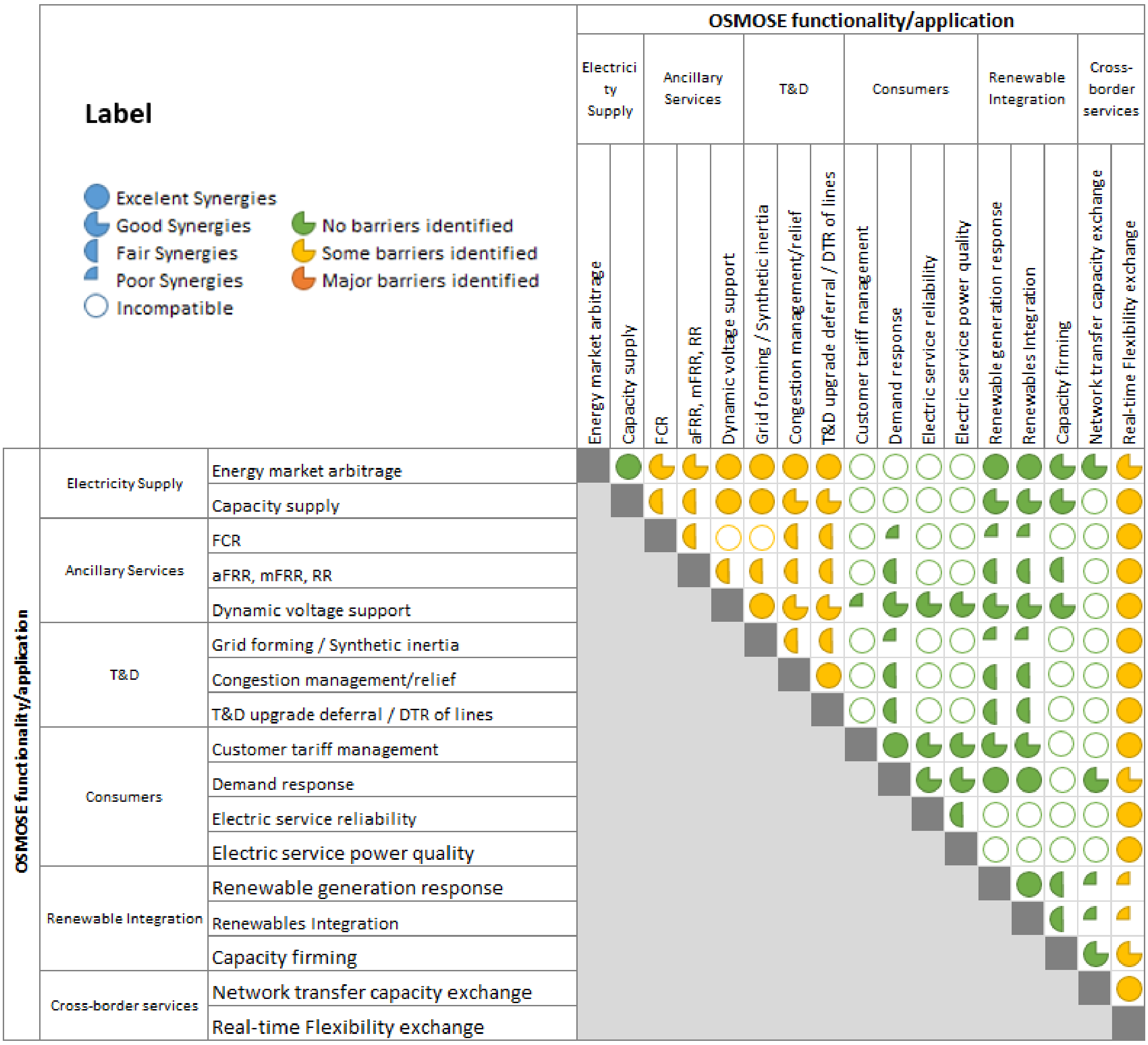

Figure 13. Synergies and market barriers faced by OSMOSE demos[70]

[70] Multiple usages are envisaged for value stacking. It is to be noted that multiple usages may or not be simultaneous, so, value stacking can be either in series and/or in parallel depending on the application.

8.3 An alternative "strawman" proposal for future electricity markets

8.3.1 Mechanisms and incentives to ensure intertemporal consistency and secure electricity supplies over all timeframes

Electricity is not a good like any other, where the intersection of short-term supply and demand automatically provides appropriate incentives for long-term capital investment, as any units that are produced can be sold over time. It thus constitutes a particular challenge for any system operator (SO) to guarantee the smooth working of the system in real time while providing appropriate long-term incentives for investment in generation capacity and network infrastructures. Three features of modern electricity systems make intertemporal consistency a particular issue:

1. **Limited storability:** it is difficult to store electricity in large quantities over long periods at competitive costs. This means that production needs to match demand second by second, even when the latter is exceptionally high. A sizeable share of production capacity is thus used only during a very limited number of hours.
2. **Network externalities:** it is more economic to connect consumers to producers through meshed networks rather than through dedicated individual lines. This produces grid-level externalities between different producers and consumers. Lately, variable renewable energy sources (VREs) such as wind and solar PV have thus strongly affected the profitability and investment outlook of dispatchable producers.
3. **Public goods issues:** electricity is widely considered a merit good, which means that continuous provision is considered a right largely independently of profitability considerations. Decades of implicit or explicit subsidisation of different technologies further complicates a transparent assessment of private and social costs and benefits. Ambitious emission reduction objectives further complicate the equation. In the electricity sector, economic sustainability always requires to be squared with political sustainability, *i.e.*, it needs to conform to social and environmental policy objectives.

These three factors produce a situation, in which the necessities of ensuring short-term balance according under the physical constraints addressed by electrical engineering are only very imperfectly correlated with the economic and financial imperatives of ensuring adequate investment in the long-term.

For many decades, this problem was resolved by handing system operations to vertically integrated monopolists with a mandate of overall welfare maximisation. Run by engineers rather than financiers and overseen by public regulators or governmental agencies, their costs would be fully reimbursed by way of regulated tariffs billed to electricity customers. While this system worked well on the technical level, it provided few incentives for cost reductions and technological innovation. This prompted successive waves of liberalisation in several regions of the United States, the European Union and several Latin-American countries.

The countries, which adopted market-based solutions for short-term energy provision and long-term investment, are, of course, keenly aware of the challenge to guarantee the intertemporal consistency between the second-to-second challenges to ensure adequate load as well as the long-term investment required for this task. Ensuring such consistency requires a great number of different steps, tasks and considerations to take account of. Figure 14 below provides a schematic overview of the complexity and the length of this timeline that is intertwined with the value chain of the power system and runs from milliseconds to decades. To put it starkly, for the computer on which this report is written, to continue to function as expected in the next few minutes, appropriate investment decisions were required several years or even decades ago, while system management electronics are required continuously to launch the appropriate control operations in the second and sub-second range. An additional challenge is constituted by the merit good nature of electricity. In optimising the system both technically and economically, the system operator is obliged to always err on the side of caution. Trial and error is not an option.

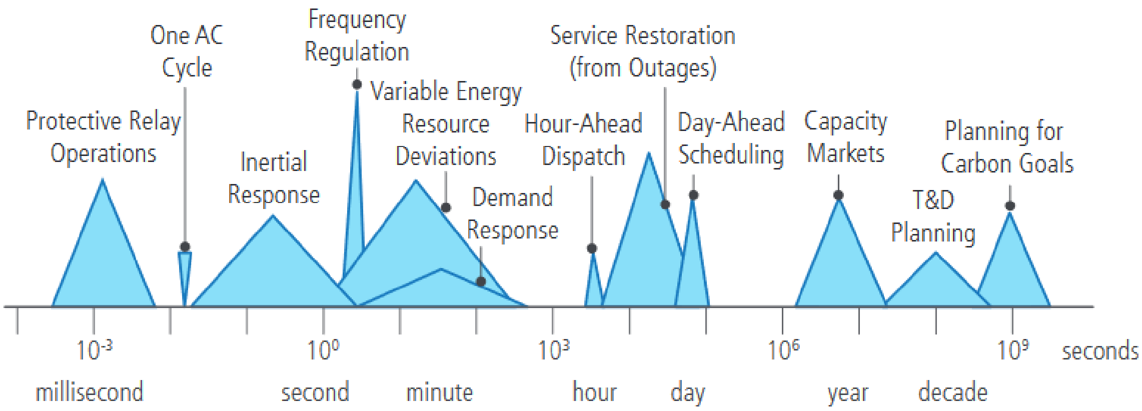

Figure 14. Electricity system operation and investments time scales. ***Source*****: US DOE (2017).**

8.3.2 The challenge of intertemporal consistency

A key question in power system management is to which extent competitive markets are best equipped to provide the goods or services at each interval of time and each step of the power value chain. Is the notion that competitive decentralised markets, as opposed to centralised auction markets or institutional and technical decision-making processes, are always the optimal instrument to provide economically and politically sustainable solutions as well as intertemporal consistency the result of sound analysis or of ideological grandstanding?

The answer owes everything to fundamental considerations of institutional economics even in such a highly specialised and technically dominated area as electricity provision: if (1) information is costless as well as transmitted and integrated immediately over all temporal sequences, if (2) other transaction costs (e.g., quality verification) and entry cost are absent and if (3) there exist no externality or public good issues, then indeed decentralised competitive markets constitute the optimal solution for the provision of electricity all along the value chain. These same criteria, by the way, apply to short-term flexibility provision as well as for dispatch and long-term investment.

Clearly, formulating the issue in this manner sets a very high bar for competitive markets. Yet, many recent developments in the past three decades since deregulated electricity markets were first introduced in the United Kingdom and the United States are actually favouring the competitive markets. On the first point, progress in information and communication technologies (ICTs) has dramatically cut information costs for individual market participants as well as for the providers of the platforms and market infrastructures that serve to exchange different services over different timeframes. Platform competition, in particular due to the availability of new block-chain technologies, is a new and growing phenomenon. While there ultimately will be limits to platform competition since liquidity considerations favour convergence, the costs for switching from one platform to another have never been so low. Modelling multiple liquidity pools will not be an easy task, the issue is however important enough to warrant consideration.

It should also be said that saying "information costs are coming down" does not mean the same thing as "information is costless". In particular, the key question is today's electricity market is "over which information shall we trade?" Some systems, e.g., New York or the UK have up to 20 (!) different markets for system services (see Box 1), which creates issues of overlap as well as lack of both liquidity and transparency. So the codification of the relevant parameters over which trading is to take place, and the segmentation of the different services to be offered and the resulting markets is a real issue in today's fast evolving markets. This, however, is by definition a centralised function that cannot be outsourced.

On the second point, quality (i.e., firmness of the ability to deliver on offers, quality of connection and of electricity delivered etc.) remains an issue but can be handled through appropriate pre-qualification procedures, penalties or the posting of performance bonds. However, competitive markets received, and continue to receive, a boost due to the continuing decline of the technically and economically efficient size of the individual establishment vying for market participation. Gas plants, both CCGTs and OCGTs, as well as VRE are today operated by firms considerably smaller than those operating nuclear or coal-fired power plants. In some short-term flexibility markets, entrants are smaller still, as distributors, aggregators, owners of an individual hydroelectric source or a set of batteries can participate with economically relevant offers.

Box 1

Examples of system services and energy markets

- Frequency control
- Frequency Containment Reserve (FCR)
- Frequency Restoration Reserve (FRR)
- Replacement Reserve
- Inertia
- Voltage control – Reactive power support
- Congestion management
- Fault and restauration (emergency) services
- Short-circuit current management
- Black start capability
- Island operation capability
- Continuous intraday
- 15 minute day-ahead market
- Hourly day-ahead market
- Monthly, quarterly and annual forward markets
- Mechanisms to foster demand response
- Markets for white and green certificates
- CO2 emission markets
- Capacity markets

Source: Benjamin Böcker (2018), Unpublished document, and author

There is however an intriguing paradox here that reveals some of the difficulties of developing stable theoretical paradigms that would allow coming to terms with the profound dynamic changes that can be observed in electricity markets today. The ever finer segmentation of system services rendered possible by ICT progress throws up a new challenge. Whereas in the old days a supplier needed to observe only the day-ahead market and perhaps the forward market, he needs now to integrate the information of 20 different markets. Previously, this information was coordinated *implicitly* rather than *explicitly* through the engineering conventions of the generators or the network operator. This created rents and inefficiencies, both probably of limited size, but allowed for technically smooth operations and provided the sort of aggregated transparency that energy economists, consultants and energy policymakers were looking for.

Integrating and making full sense out of the information provided by the complete set of today's explicit markets requires sophisticated computational tools. Automated trading is thus rapidly increasing its share of market operations. This *integration challenge* may well create new forms of monopoly power. Only the most technically savvy operators will be able to take full advantage of the different information streams. This may or may not be a good thing. On the one hand, these operators may well be the utilities of the future, capable of integrating market information with the “big data” arising from large numbers of individual customers as well as with the technical constraints and economic characteristics of newly established portfolios of technologies that can play the full gamut of timeframes from system service that need to be supplied in the range of milliseconds to investment decisions that reach out several decades into the future. On the other hand, one may witness a new dominance of de-localised information processors that will be difficult to hold to account. Most of their portfolios will be virtual as they outsource the building and running of plants to sub-contractors. Regulators and policymakers will have difficulties to communicate public goods issues as pricing pressures create a race to the bottom in terms of environmental performance, social responsibility and public service obligations. Multiplying the number of decentralised market platforms with explicit prices, especially if they are unmoored from any coordinating oversight by the system operator (SO) or the regulator, thus has corollary effects that are not easily captured in the traditional economic categories of public goods.

This brings us to the third point, the existence of externalities and public goods. By the very nature of yet to be fully codified external effects, these issues are subject of debate. They are also strongly dependent on a country’s specific situation, as well as its generation mix. However, the vast majority of external effects in electricity provision can be summarised in three major categories of public goods (1) the security of supply including adequate capacity provision, (2) environmental integrity and (3) considerations of social acceptability and regional cohesion. Security of supply considerations have both a short-term dimension of physical adequacy and technical reliability as well as a long-term dimension centred on considerations of geopolitical dependency and resource adequacy. There is a vigorous debate, which goes right to the heart of the question of economic optimality of the market paradigm, whether deregulated markets on their own provide adequate levels of capacity (see below for further discussion). In conceptual terms, the longer-term issues are less controversial as it is understood that to the extent that external effects arise, they must be dealt with at the political level.

A major challenge to the performance of competitive markets has been the variability of VRE, in particular when the latter are financed with out-of-market measures. It can be shown, that in a pure market system, CRE penetration will progress only to the economically optimal level permitting all participants to recuperate their costs under the habitual constraint of a small number of scarcity hours. However, introducing VRE into essentially balanced systems with the help of incentive measures such as feed-in tariffs (FITs) has significant impacts on the economic viability of dispatchable generators, which are necessary to guarantee supply in hours of low VRE production and high demand. These impacts are transmitted through two channels (a) a price effect as average prices fall in the presence of VRE with zero short-run marginal costs and (b) a compression effect as the load factors of dispatchable generators decline.

Figure 15 and Figure 16 below show that these impacts are very significant even when VRE penetration rates are very reasonable. The decline in the profitability of dispatchable operators poses a serious issue for the security of supply, as the latter will leave the market as soon as their fixed costs of operations and maintenance (O&M) are no longer covered. In the short-and medium-run this implies a greater risk of supply interruptions and a higher number of scarcity hours. In the long-run, existing generation assets with high capital costs will still leave, while new assets with lower fixed costs such as open-cycle gas turbines or diesel engines will be attracted by scarcity prices.

		10% Penetration level		30% Penetration level	
		Wind	*Solar*	*Wind*	*Solar*
Load losses	***Gas Turbine (OCGT)***	-54%	-40%	-87%	-51%
	Gas Turbine (CCGT)	-34%	-26%	-71%	-43%
	Coal	-27%	-28%	-62%	-44%
	Nuclear	-4%	-5%	-20%	-23%
Profitability losses	***Gas Turbine (OCGT)***	-54%	-40%	-87%	-51%
	Gas Turbine (CCGT)	-42%	-31%	-79%	-46%
	Coal	-35%	-30%	-69%	-46%
	Nuclear	-24%	-23%	-55%	-39%
Electricity price variation		-14%	-13%	-33%	-23%

Figure 15. **The combined impact on price declines and the compression effect on the profitability of dispatchable operators in the presence of VRE. *Source*: OECD Nuclear Energy Agency (2012)**

The resulting re-composition of the capacity mix will however result in higher overall system costs, basically because a greater number of GW of capacity will produce over a lower number of hours. More importantly, until such a new equilibrium is reached there are serious risks of disruption. In all cases, both during the transition and in the new equilibrium, price volatility will increase. Note also that when nuclear energy with its high fixed costs is substituted over the capacity cycle with a mix of VRE with out-of-market finance and gas-fired generation capacity with low fixed costs CO2 emissions will increase. A case in point is Germany, where massive investments in VRE capacity, now approaching 100 GW, have not reduced CO2 emissions in the electric power sector since 2009.

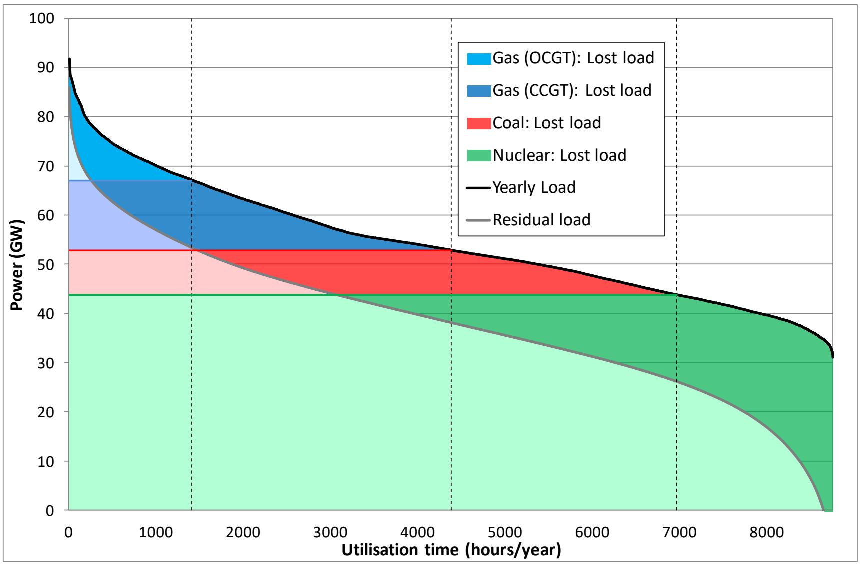

Figure 16. **Load losses of dispatchable operators with a 30% share of wind power. *Source*: OECD Nuclear Energy Agency (2012)**

8.3.3 The public good of the security of electricity supply

According to a generally accepted definition adopted by Eurelectric and others "the security of energy supply is the ability of the electrical power system to provide electricity with a specified level of continuity and quality in a sustainable manner." This is a good starting point even though a number of alternative definitions exist. It does not even matter whether security of supply is renamed as adequacy, reliability or resilience.[71] Of course, it would be possible to introduce fine semantic distinctions between these concepts. They all come to the question of the level of confidence that consumers can have to be reliably served.

All general definitions inevitably hide a number of different temporal and technical dimensions that need to be addressed in order to ensure security of electricity supply (see Figure 17 below for a purely indicative illustration).

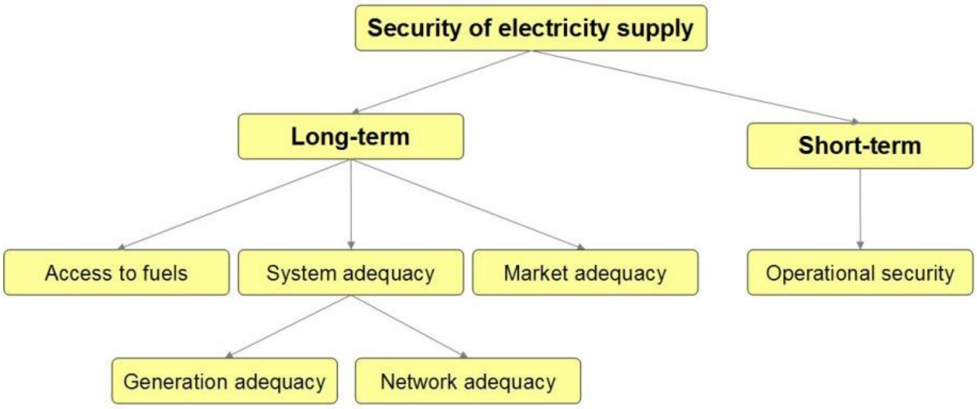

Figure 17. **Dimensions of the Security of Electricity Supply. Source: Eurelectric**

Looking at the different temporal dimensions, security of supply in the long-term inevitably includes adequate investment and can thus be rephrased as a resource adequacy issue. This holds both for generation and transmission capacity. While the latter is frequently provided under regulated returns, the former is not. The profitability of investments of deregulated generation assets thus depends on profits in short-term markets. As is well known, in the absence of proper scarcity pricing (Cramton and Stoft 2006b), market profits are not enough to recover fixed costs. The existence of a small number of scarcity hours on which a large share of profits depends, but that are impossible to predict *ex ante* with precision increases investor risk, in particular if there are markets missing for hedging long-term investment positions in the market (D. M. Newbery and Stiglitz 1984; de Maere d'Aertrycke, Ehrenmann, and Smeers 2017).

[71] An alternative but largely equivalent definition is thus provided by the US electricity market regulator FERC who defines adequacy as "the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements (Momoh and Mili (2010), p.134).

The long-term difficulty of financing capacity is, of course, intimately linked to the structural issue of non-stockability resulting in inelastic short-term demand and the need to match demand and supply.[72] Moving closer to real-time, markets are required to deal with short-term contingencies. While this could in principle be subsumed in the general definition of the security of supply, some commentators prefer to designate as resilience or system quality.[73] In particular, it may include the ancillary services listed in Box 1, such as reserves provision, frequency regulation, voltage control, congestion management, black start capabilities. The measure of such resilience is based on administratively defined security standards indicating the *ex-ante* probability of involuntary loss of load expectations (LOLE). The main issue here is the *administrative* determination of the reliability standard, since it is, by definition, impossible to determine a user-defined value of reliability. Given that the value of lost load (VOLL) refers to *involuntary* demand response, it is logically impossible to convey the associated utility loss. There is an intrinsic public good elements to such reliability and security of supply issues (P. Joskow and Tirole 2007; William Hogan 2005).

> *"The market cannot operate satisfactorily on its own. It requires a regulatory demand for a combination of real-time energy, operating reserves, and installed capacity, and this demand must be backed by a regulatory pricing policy. Without this reliability policy, the power system would under-invest in generation because of the demand-side flaws. ((Stoft 2002b), p. 108)."*

Questions of flexibility provision have risen to the forefront of the concerns of electricity system operators due to the added needs induced by the variability of wind and solar PV generation capacity. As non-dispatchable resources, they may add inelasticity to the short-run marginal costs (SRMC) on the supply side to the inelasticity on the demand side (see "Do renewables add to the problem? In (Cramton, Ockenfels, and Stoft 2013). The exact impacts are a function of the regulatory framework and he incentives to which VREs are exposed. If curtailment is possible, it is frequently the lowest-cost flexibility option. However, simple feed-in tariff schemes may exacerbate the problem as VRE is solely defined by the weather with no regard to the flexibility needs of the system.

The inability of markets to value reliability can also be linked to two more technical issues, which reformulate the fundamental logical impossibility to privatise the public good of security of electricity supply (see, for instance, section "What the Market Can't Do" in ((Stoft 2002b), p. 15). The first one relates to a lack metering and real-time billing at the origin of the lack of demand responsiveness to price or, technically, a lack of demand elasticity. The idea is that with more elastic demand, i.e. *voluntary* demand response, *involuntary* demand response during VOLL hours would no longer be necessary. The argument is fundamentally sound but underestimates the inertia and transaction costs in the residential sector, which severely limit the potential of real-time metering. People will not

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72 While the issue of inflexible short-term demand is real, it is a frequent error made even by seasoned experts to assume that price caps exacerbate the short-fall in revenues resulting from variable cost pricing referred to as the "missing money" (Cramton and Stoft 2006b; Cramton, Ockenfels, and Stoft 2013). In a well-functioning electricity market, price caps will only increase the number of scarcity hours (the number of hours when prices hit the cap) as generators will reduce capacity to bring costs and revenues in line.

73 Security of operations as "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. This issue also relates to the ability of the power systems to respond to dynamics or transient disturbances arising within the system (Momoh and Mili 2010), p.134)."

postpone their meals to save a handful of cents on their electricity consumption. The question is, of course, in the context of the OSMOSE project to which extent storage can infuse much-needed elasticity and thus substitute for the lack of responsiveness of domestic and industrial consumers.

The second issue relates to the inability to selectively disconnect consumers according to their presumed willingness-to-pay. Such real-time control of power flows to specific customers might soon become technically feasible and thus, in principle, enable the physical enforcement of bilateral contracts and results in the system operator being the default supplier in real-time. In other words, customers willing to pay insurance would continue to be served, while others would be disconnected.

The argument forgets the public nature of electricity supply, which would inevitably result in free-rider issues und the structural under-provision connected with EOMs. Street-lighting is a simple evocative example. However, even the supposedly private use of electricity, think of restaurants, billboards, cooling and heating of private dwellings in apartment buildings etc. and it becomes obvious that the externalities that connect electricity consumers that ultimately constitute the public nature of electricity consumption will not go away just because it becomes technically possible to disconnect particular customers (see (Keppler 2017; Schwenen 2014; Michael Hogan 2017)for different takes on the public nature of electricity consumption).

Another manner to introduce greater elasticity into electricity demand might be the introduction of a share of auto-production as an alternative to grid-based supplies. Some researchers consider this dual supply arrangement a step towards a “soft market cap”:

> *“The ability to have electric service independent of the grid does not mean that customers will choose to physically disconnect from it. Many customers may choose to remain connected, even if they have the capability to operate economically independent of the grid, just as many customers with mobile phones also retain their landline telephones. However, the mere ability of significant numbers of customers to disconnect would likely create a “soft” market-based cap on how much utilities can charge their customers for being connected to the grid (Corneli and Kihm 2015, p. 6).”*

Behind the metre auto-production can indeed function as a source of flexibility at the level of the system and thus of security of supply during demand peaks similarly to demand response or storage. It does, however, also pose a number of difficult economic issues. For instance, the financing of firm grid-connected capacity will become more difficult if consumers choose to auto-produce during periods of high market prices. Similarly, the financing of transmission and distribution grids would have to be rethought, potentially switching from tariffs based on kWh consumed to tariffs based on the kW of the connection. Again, there is a tricky public goods issue here. Auto-producers with dual connections, especially those with VRE, benefit from grid services when production is low but do not fully contribute to its financing. While auto-production is a potential provider of flexibility, pricing will have to be carefully rethought.

8.3.4 The limits of marginal cost pricing in energy only markets (EOM) to provide adequate levels of capacity and flexibility

A number of experts still think that all aspects of electricity provision, over all timeframes, from long-term capacity to real time ancillary services, can be properly priced out in competitive energy-only markets. This comes back to marginal cost-pricing with a number of scarcity hours with involuntary demand response to bring capacity costs and revenues in line. They thus consider externalities (i.e., public goods issues), asymmetric information or transaction costs as negligible. The idea is to provide system-wide competitive markets over all identifiable services and all time segments. Issues of a lack of liquidity, overlapping markets or market power are considered secondary. Researchers of the *Regulatory Assistance Project (RAP)* have thus established a list of conditions for such marginal cost-based markets. While one may, and we think must, disagree with thus an extreme and to some extent simplistic vision for the working of the electricity system, it provides precisely because of its simplicity a useful starting point for discussions. The points they make include:

- On market size: aggregation of larger balancing areas and increased interconnectivity with neighbouring markets; increased transmission investment to mitigate internal congestion;
- Forecasting: invest in more accurate weather forecasting; long with a forecast of gross demand, establish a procedure for forecasting variable resource production and combine the two to derive a net demand forecast; use net demand forecasts to assess the demand for critical flexibility services
- Demand response: enable demand to be more responsive; ensure that all qualifying demand-side options are fully able to participate in these markets, both directly and through aggregators.
- Capacity provision: establish a methodology for setting the maximum value to the system of each additional increment of capability up to the target quantity; the desired resource capabilities can be procured through either enhanced services markets or apportioned forward capacity mechanisms, depending on the individual market circumstances.
- Ancillary services: shorten scheduling intervals and enhance existing services markets;
  (Adapted from Hogan and Gottstein 2012).

The RAP experts thus further tweak the vision that guided market liberalisation since the 1990s, which maintains that an appropriately segmented suite of energy-only markets (EOMs) with marginal cost pricing over different time-frames can adequately supply all necessary aspects of an electricity system. In this approach also markets for ancillary services are just markets for energy delivered at very short-notice over peculiar timeframes. This includes capacity, which is less thought of as a factor input into the mass production of energy (which would imply average cost pricing), but more of as an independent additional service provided by generation equipment designed to run only for a handful of hours per year or demand response. Steven Stoft set out the newly existing link between energy production and capacity provision in deregulated electricity markets in the following manner:

> *"Under regulation, operating-reserve policy and investment policy are completely separate. In a market, they are tightly linked through expectations. Currently [i.e., under liberalisation], regulators and engineers intervene in markets to determine how much will be paid when operating reserves are in short supply. These prices largely determine the revenue stream that pays the capital costs of new peakers and pays an equal amount toward the capital costs of all other generators. In this way, operating-reserve and price-cap policies determine investment in generation and the equilibrium level of installed capacity (Stoft (2003), p. 470)."*

While there is still a feedback loop through centrally determined reserve requirements, it is essentially *relative scarcity* during normal operating hours, which implicitly sets capacity targets and lets markets fulfil those in a decentralised manner. Operating reserve requirements and the resulting revenue streams thus function as an implicit capacity mechanism.

In general terms, the vision that a slight tweaking of the operations of EOMs, which might be considered a refined form of current **Current goals achieved**, can solve also capacity and flexibility issues still underlies European energy market policy-making today. Similarly, flexibility would be implicitly valued on energy markets over shorter time-frames. While attractive from a conceptual point of view, the question is whether this vision is adequate for the decentralised, desynchronised and decarbonised systems of the future.

There are a number of reasons why its realisation might be difficult in light of the realities of modern electricity system. One reason is that the segmentation of the different timeframes between the registration of bids and delivery will necessarily have an arbitrary element. It will never be completely possible to avoid overlaps as well as strategic behaviour making correlated bids between different markets and thus the exercise of market power. On the relationship between balancing and Intraday markets, Weber, for instance writes:

> *"This simple relationship [between the balancing and the Intraday markets] may… be disturbed if the bids on the reserve markets consist of a capacity and an energy bid, as it is notably the case in Germany. Given that they earn a capacity revenue, power plant operators may then offer lower energy prices on the reserve markets than on the intraday market. If the TSOs use those prices for pricing balancing energy, situations may occur, where the balancing energy price is lower than the intraday market price. This obviously creates distorting incentives for wind power producers and other balance responsible entities (Weber, 2010, p. 3161)."*

A similar case of the potential for the abuse of market-power by coordinating bids over several markets is reported by Knaut *et al.*:

> *"Two problems… may arise from the current (weekly) market design. First, the weekly procurement leads to inefficiencies as operators need to withhold capacities for a whole week and [thus] cannot fully participate in the hourly spot market. There is a missing market for hourly balancing power products that could be solved by an hourly procurement of balancing power. Secondly, we observe that large players with a broad portfolio of power plants are able to provide balancing power at lower costs, especially in a weekly auction. These economies of scale for large players may lead to highly concentrated markets and the possible abuse of market power... It is well understood that shorter time spans lower costs and may increase market concentration (Knaut et al. (2017), p. 2)."*

A particular issue is also posed by the provision of inertia or reactive power services. As is well known, inertia has become something of a hot topic due to the declining role of stationary generators with large spinning masses such as steam turbines for nuclear, coal or combined cycle gas plants. The latter provided stabilising inertia as a free positive externality. This is no longer the case. Modern power electronics is capable of replicating "synthetic inertia" also in systems with large shares of decentralised and variable renewables. However, the very high costs of transporting reactive power cause this to be a local service with intrinsic market power issues. This can be an issue also for operating reserve services, which ideally should be differentiated according to time and place. This renders the creation of homogenous national or European markets an insufficient solution. Prices for flexibility on a European market are likely to be much lower than the true system costs at the local level, where operators would have to resort to costly re-dispatch. At the same time, calling for a massive, and costly, extension of transmission and distribution grids is again too simplistic, as many of these constraints might of a temporary nature, depending on local patterns of generation, consumption and storage, and might disappear as quickly as they arise, reacting elastically to changes in incentives, behaviour and technologies. One of the technological parameters in this context is the emergence of local flexibility markets based on block-chain protocols without third-party intermediation. Regulators and the operators of electricity markets are thus faced with “a jig-saw puzzle rather than a problem in hydrodynamics”. One of the solutions currently being proposed by EPEX Spot the European electricity market operator is thus the creation of local “pop up” markets of limited duration which can assist overcoming congestion or flexibility problems in precisely localised perimeters. It is quite obvious that this sort of “bootstrapping” provides a pragmatic addition to the existing tool-kit for muddling through rather than a horizon for a convincing long-term vision of an equilibrium solution for European electricity markets in a perspective 2050.

The complexity of the jig-saw puzzle and size of the challenge of designing appropriate short-term markets EOM at a European scale becomes strikingly clear when looking at the table below compiled by Ocker *et al.* (see Table 1). The intuitive reaction to call for European harmonisation might not be the correct, or at least not the sufficient, answer. Each one of these markets has been designed in order to respond optimally to national flexibility requirements. Their diversity thus reflects the number of parameters that must be taken into account to provide the flexibility a system needs. There is a sort of “short-blanket syndrome” at work here. If EOM trading five minutes before delivery is an appropriate solution for Belgium and the Netherlands, two small countries with high flexibility needs due to VREs and sufficient interconnections, such an arrangement would be met with insufficient liquidity in a large country such as Poland with limited interconnections and relatively far smaller flexibility needs. Pulling the blanket in one direction would leave partners on the other side exposed and vice versa.

It also remains questionable to which extent a coordinated move of European electricity markets closer towards real-time would bring massive efficiency gains. Ocker *et al*. in a recent research paper estimate the efficiency gains of moving from a weekly (!) balancing market design to an hourly one between 17% in winter weeks and 14% in the summer week (Ocker *et al*. (2018), p. 24). Needless to say, the efficiency gains of progressively smaller increments, say, moving from hourly to 15-products would be smaller still. While it is clear that such estimates provide qualitative indications of orders-of-magnitude rather than firm results, there do exist declining marginal returns for moving ever closer to real-time in a harmonised fashion at the European level as technical constraints, network congestions and transitory local issues set limits for the smooth minimisation of the variable costs of flexibility provision.

	Power market characteristics		*Balancing power market characteristics*			*Auction characteristics*	
	vRES share (2014)[1]	**Latest possible trading option**[2]	**FCR (automatic)**	**FRR (automatic)**	**RR**	**Pricing rule**	**Scoring rule**
Austria	7.3%	30min	PB; s; w; m.-o.; 1x168h; 1MW	PB&EB; ±; w; m.-o.; Mo-Fr 8am-8pm, rest; 5MW	PB&EB; ±; w; m.-o.; 42x4h; 5MW	PaB	lowest PBs
Belgium	9.2%	5min	TP; ±; m; *n/a*.; base, peak, offpeak; 1MW	PB&EB; ±; m; m.-o.; base, peak, offpeak; 5MW	PB&EB; ±; y; *n/a*.; base, peak, offpeak; 5MW	PaB	SP
Czech Republic	4.4%	*Day-ahead*	PB; s; d; *n/a*; 24x1h; *n/a*	PB; ±; d; p; 24x1h; *n/a*	PB; s; d; m.-o.; 24x1h; *n/a*	UP	lowest PBs
Denmark (DK1/DK2)	44.7%	60min	PB; ±; d; *n/a*; 6x4h; 0,3MW	PB; s; m; p.; 24x1h; 0,3MW	PB&EB; ±; d; *n/a*; 24x1h; 10MW	UP (DK1), PaB&UP (DK2)	*n/a*
Estonia	8.7%	60min	*provided by russian TSO*	TP; *n/a*; *n/a*; m.-o.; 24x1h; 5MW	TP; ±; *n/a*; *n/a*; 24x1h; 5MW	PaB	*n/a*
Finland	1.4%	60min	*n/a*; s; *n/a*; *n/a*; 24x1h; 1MW	EB; ±; *n/a*; p; 24x1h; 10MW	*non-existent*	UP	*n/a*
France	5.6%	30min	*compulsory, regulated prices*	*compulsory, regulated prices*	TP; ±; y; m.-o.; *n/a*; 10MW	PaB	*n/a*
Germany	18.2%	30min	PB; s; w; m.-o.; 1x168h; 1MW	PB&EB; ±; w; m.-o.; Mo-Fr 8am-8pm, rest; 5MW	PB&EB; ±; d; m.-o.; 6x4h; 5MW	PaB	lowest PBs
Hungary	1.9%	120min	PB; ±; *n/a*; *n/a*; 24x1h; *n/a*	PB&EB; ±; *n/a*; m.-o.; 24x1h; *n/a*	PB&EB; ±; *n/a*; m.-o.; 24x1h; *n/a*	PaB	*n/a*
Iceland	0.0%	*Day-ahead*	TP; s; w; m.-o.; 24x1h; 1MW	TP; s; w; m.-o.; 24x1h; 1MW	TP; ±; w; m.-o.; 24x1h; 1MW	UP	lowest TPs
Italy	13.1%	250min	*compulsory, regulated prices*	EB; s; d; p; 24x1h; 1MW	EB; s; d; m.-o.; 24x1h; 1MW	PaB	*n/a*
Latvia	2.1%	60min	*provided by russian TSO*	*manual*: *n/a*; ±; *n/a*; m.-o.; 24x1h; *n/a*	*non-existent*	*n/a*	*n/a*
Lithuania	13.7%	60min	*provided by russian TSO*	*manual*: TP; *n/a*; d; m.-o.; 24x1h; 5MW	TP; *n/a*; d; m.-o.; 24x1h; 5MW	UP	lowest TPs
the Netherlands	6.4%	5min	PB; s; w; m.-o.; 1x168h; 1MW	PB&EB; ±; d/y; m.-o.; *n/a*; 4MW	PB&EB; ±; d/y; m.-o.; *n/a*; 20MW	PaB & UP	lowest PBs *(FCR), n/a*
Norway	2.0%	60min	PB; s/±; d/w; *n/a*; 24x1h; 1MW	PB&EB; ±; w; p; *n/a*; 1MW	*non-existent*	UP	*n/a*
Poland	6.0%	180min	EB; ±; *n/a*; *n/a*; 24x1h; *n/a*	EB; ±; *n/a*; *n/a*; 24x1h; *n/a*	EB; ±; *n/a*; m.-o.; 24x1h; *n/a*	UP	SP
Portugal	27.9%	195min	*compulsory, no compensation*	PB; ±; d; p; 24x1h; *n/a*	PB&EB; ±; d; m.-o.; 24x1h; *n/a*	UP	lowest PBs
Romania	18.4%	90min	*compulsory, no compensation*	TP; ±; d; m.-o.; 24x1h; *n/a*	TP; ±; d; m.-o.; 24x1h; *n/a*	UP	lowest TPs
Slovenia	2.1%	60min	*compulsory, no compensation*	PB&EB; *n/a*; y; p; 24x1h; *n/a*	PB&EB; *n/a*; y; m.-o.; 24x1h; *n/a*	PaB	*n/a*
Spain	28.3%	195min	*compulsory, no compensation*	PB; ±; d; p; 24x1h; *n/a*	PB&EB; ±; d; m.-o.; 24x1h; *n/a*	UP	lowest PBs
Sweden	9.2%	60min	PB&EB; s; d/w; *n/a*; 24x1h; *n/a*	PB&EB; ±; w; p; *n/a*; *n/a*	*non-existent*	PaB	*n/a*
Switzerland	1.6%[3]	60min	PB; s; w; m.-o.; 1x168h; 1MW	PB; s; w; p.; *n/a*; 5MW	PB; ±; w; n/a; 6x4h; 1MW	PaB	lowest PBs (FCR), SP (FRR, RR)
Serbia	0,0%	*Day-ahead*	*non-existent*	TP; ±; d; p; 24x1h; *n/a*	TP; ±; d; *n/a*; 24x1h; *n/a*	UP	lowest TPs
United Kingdom	11.9%	75min	PB&EB; ±; m; *n/a*; Mo-Fr, Sa, Su; 10MW	PB&EB; ±; m; *n/a*; Mo-Fr, Sa, Su ; 10MW	PB&EB; s; m; *n/a*; Mo-Fr, Sa, Su; 50MW	PaB	*n/a*

For supplementary information on the sources for this table please refer to the following document: http://games.econ.kit.edu/img/Comments_Sources_Design_of_European_Balancing_Power_Markets.pdf

Abbreviations: ***manual***=manual activation; **PB**=power bid and/or **EB**=energy bid or **TP**=total price; s=symmetric product (no distinction between positive and negative balancing energy) or ±=distinction between positive and negative balancing power; procurement: **d**=daily, **w**=weekly, **m**=monthly or y=yearly; **m.-o.**=merit-order activation of balancing energy or **p**=pro-ratio/parallel activation of balancing energy; **24x1h**=24 one-hour time slices per day; **5MW**=minimum power offer is 5MW; **PaB**=Pay-as-Bid pricing or **UP**=Uniform pricing (for EB and/or PB); **SP**=Stochastic Programming or **lowest PBs**/**TPs**=lowest capacity bids/total prices are considered until balancing demand is met; ***n/a***=parameter not available (e.g. not published)

[1] Ratio between net electricity produced from wind and solar power and the electrical energy available for consumption.
[2] Latest possible trading option before physical delivery on the primary spot market platform of each country; over-the-counter trades are not considered.
[3] Ratio between gross electricity consumption from wind and photovoltaics and the final net electricity consumption.

Table 1. An overview of markets for ancillary services in Europe.

Souce: Ocker *et al*. (2016), p. 5.

8.3.5 An alternative vision proposed by OSMOSE: By 2050 all attributes of electricity provision will be financed by fixed annual ex ante payments

In this situation, the ability of competitive electricity markets to provide the high levels of security of supply to which European consumers have grown accustomed to is severely tested. It matters little in the context of the Osmose project under which moniker this challenge is addressed, whether it is referred to as adequacy, resilience, reliability or security of supply. While the latter would encompass also issues such as geopolitical dependency and resource availability, these are outside the scope of Osmose. What remains is the fact that energy-only markets face a major challenge. The interference with market mechanisms in order to promote VRE has created a slippery slope of added interventions. Policymakers, market organisers such as the European bourses and regulators have responded mainly in two ways (a) organising different forms of long-term capacity remuneration mechanism (CRM) and (b) creating new markets and mechanisms for the provision of flexibility and system services closer to real time. The two extremes of the temporal spectrum outlined in Figure 14 thus gain at the expense of hourly day-ahead market that was thought for a long time to provide the relevant price of electricity. This is less and less the case.

Paradoxically, the technologies participating in the long-term end of the spectrum, i.e., capacity mechanisms, might be the same ones as the ones in the short-term end closer to real time. Storage and demand response are cases in point. What changes between a capacity mechanism and, say, a balancing market is the form of remuneration; guaranteed up-front payments remunerating capacity investment in one case, variable prices remunerating flexibility and scarcity services during hours of high demand in the other. In both cases, the commodity that is valued is capacity rather than energy. This is a result of the high ratio of energy produced to firm capacity that is typical for VRE. This is one of the few certainties surrounding the electric power systems of the next 30 years: electric energy will become of increasingly lesser value, while capacity and flexibility will continue to increase in value. In this, capacity and flexibility are to some extent two sides of the same coin: capacity is the long-term ability to provide flexibility at all times. Of course, the term flexibility also covers a number of technical constraints in terms of modulating capacity over the duration of seconds or minutes, yet this does not change the deep intrinsic link that unites them. In fact, close to real time system operators again use up-front fixed payments to remunerate participants in the primary reserve mechanism rather than resort to a payment on the basis of marginal costs.

For the time being, energy only markets such as the EPEX Spot day-ahead market and the EEX forward markets remain, financially speaking, the most important part of the electricity system. However, the dynamic has turned against them. The shift of the point of gravity of electricity systems towards remunerating kW rather than kWh, fixed capital outlay rather than variable costs is an intrinsic feature of low carbon systems given their high capital intensity.

Deregulated electricity markets setting prices according to variable costs were created for gas turbines with a relatively low ratio of fixed costs to variable costs. Indeed, carbon emissions and high variable costs go together. The latter are due to the high costs of the fossil fuels. When fossil fuels themselves are cheap and carbon pricing is absent, such as is currently the case for shale gas in the United States, they will dominate any market. However, markets with sufficiently high marginal costs, whether due to the intrinsic costs of hydrocarbons such as methane or due to carbon pricing, do allow financing investment on the basis of market prices.

In low carbon markets instead, in particular if the costs of emitting carbon costs do not raise prices at the margin, earning revenues through the sale of kWh is not sufficient for investment. This holds in particular for variable renewables which are doubly penalized as their auto-correlation in production drives down their revenues even below already low average electricity prices. The need for fixed cost pricing also holds for flexibility provision, an increasingly important issue in all electricity systems, primarily due to the variable output of renewables.

Remunerating demand response on the basis of variable costs was long considered possible. Models often included it as a technology without fixed capital costs thus allowing it to close the "missing money" gap without any recourse to scarcity hours priced at VOLL. This would have significantly strengthened the case for energy-only markets. However, overwhelming empirical evidence, see, for instance the 2017 by the French Environmental Agency (ADEME), shows that industrial demand response is being provided on an annual per kW basis rather than on a per kWh basis. Residential demand response to the extent that it can be leveraged due to the high costs of utility losses of load shifting and load shedding is to some extent following the same pattern. Clearly, individual residential consumers will not intervene in the wholesale market based on marginal cost-pricing, transaction costs are far too large and the Cost-Benefit trade-offs not nearly advantageous enough. Instances of demand modulation will thus be triggered through the automated off-site systems of aggregators. The question is whether the latter will sell these tweaks in the load curve into the energy or the capacity markets. The way the system is heading, capacity markets will eventually offer more attractive remunerations. In energy-only markets, the possibility to modulate the output of variable renewables with its comparatively low market value is usually the cheapest form of flexibility.

In the case of storage, the dominance of fixed capital costs over variable costs is even more pronounced. Storage has no technical variable costs but only intertemporal opportunity costs in the sense that selling a unit of stored energy at hour h_i means that the same unit can no longer be sold later at hour h_{i+j}, where $j \in \{1, 2, \dots, n\}$. The number n, however is purely a function of the capacity of the storage unit. In other words, the capacity of a storage unit will be a function only of electricity price dynamics without any regard to variable costs of production in the traditional sense. The specific role of storage as a pure capital investment with only fixed costs to be considered can also be understood by looking at its substitutability with electricity transport and distribution networks. A battery can substitute for network access. Two batteries may substitute for a line connection between two points of production/consumption. In essence, batteries fulfil the smoothing function that has been traditionally been fulfilled by the pooling of individual production and consumption profiles through electricity networks. Again, storage as a capacity and flexibility provider thus reinforces the shift towards the concentration of the overall costs of electricity systems in the up-front fixed capital costs.

However, if capacity and flexibility rather than energy are becoming the centre of gravity of the electricity system rather than adjuncts to the production of electricity, this has profound implications for policy-making, energy system modelling as well as the structure of utilities or price formation. Much policy-making and modelling is still based on the premise that energy systems exist to produce the maximum amount of electric energy at the lowest cost. This premise no longer holds in a 2050 perspective. OSMOSE will have to develop a vision of the electricity sector that puts capacity and flexibility, not energy, at the centre. What would that mean? For instance, it could conceive, as a test case rather than as an empirical reality, a system in which energy is most of the time "too cheap to metre" and all capacity is financed through a mix of fixed annual payments from distributors to generators for a given amount of band-width, supplemented with a small complement of scarcity payments. This would trickle through to consumers, whose tariff is a monthly flat-rate, perhaps allowing for some back-up storage capacity (provided by the distributor) in times of scarcity.

In practice, of course, energy markets will not disappear overnight, but the direction of travel will not favour their growth or their ability to create value. In this situation, it is futile to oppose short-term flexibility and long-term capacity. As said, both can refer to the same technologies providing the value of reliability in a system awash with low-value but unreliable energy.

This vision of a profound transformation of the working of the electricity sector is less radical than it might seem at first sight as it mirrors developments in other sectors for non-storable goods such as telecommunications and information technology. Here the constraining factor is also capacity at the time of peak demand rather than per unit cost. Similarly, consumers care strongly about the quality and reliability of service rather than obtaining the best prices for the marginal unit of consumption. In both cases, there are also strong externalities in security of supply, which makes auctioning solutions at the wholesale level, where overall quantities are set by the system operator, a particularly attractive option. Auctioned capacity of a defined quality can then be handed down to retail customers in the form of flat-rate offers by distributors and aggregators.

The idea of a system with very strong increasing returns to scale, built around demand response, storage, network and capacity services financed by fixed annual or monthly instalments "flat rates" that depend only on the kW-size of the connection but not on consumption largely corresponds to a both politically and socially attractive vision of the energy future. The trouble is that decision-makers at national and the European level continue to cling to the idea that this vision can be realised by perfecting the energy-only market. The idea is that a price signal from real-time markets with high granularity feeds through all-the way into a long-term forward supply markets determining investment. In the most abstract of visions this is not impossible. In a perfectly transitive system, the price of electricity during scarcity hours *is* the marginal cost of capacity. The trouble with this vision is only that the price volatility that come with a load profile that alternates essentially hours of zero prices with a highly uncertain number of hours with scarcity prices will make for absurdly high capital costs. Since capital costs are all that matters in the electricity systems of the future, insisting on the predominance of energy-only markets is leading to an impasse, whose effects are already being felt now but whose impacts will dramatically increase as time goes by.

However, the OSMOSE project will set out and test an alternative vision in which all services to the system except hourly energy dispatch and the forward provision of energy are provided on the basis of fixed payments dimensioned on capacity rather than on energy. These payments are decided in annual *ex ante* auctions organised by system operators at the transmission and the distribution level, which will determine needs on the basis of projections. This vision is also easily compatible with a notion of **Accelerated transformation** as it can be scaled down very finely to the local level. At this level, its transparency and simplicity have a particular bearing. The flat-rate approach provides certainty and visibility in particular for small producers and consumers with rudimentary financial book-keeping, who care little about the second-order optimisation of marginal costs but care hugely about knowing their outlays and revenues for the year. In alternative to a horizontal structure of ever more segmented markets based on variable costs and marginal cost pricing, the financing of the complete electricity systems through a vertically cascading structure of progressively finer fixed *ex ante* annual payments when progressing from the system level to the local and the household level will thus be developed as a major for a 2050 vision of a deeply decarbonised and decentralised European electricity system in the OSMOSE project.

8.3.6 Futher references

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