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INTERRFACE

TSO-DSO-Consumer INTERFACE aRchitecture to provide innovative Grid Services for an efficient power system

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Abbreviations

ACER	Agency for Cooperation of Energy Regulators
API	Application Program Interface
BRP	Balance Responsible Party
BSP	Balancing Service Providers
CACM GL	Capacity Allocation and Congestion Management Guideline
CAISO	California Independent System Operator
CEC	Citizen Energy Community
CEER	Council of European Energy Regulators
CEP	Clean Energy Package
DC NC	Demand Connection Network Code
DER	Distributed Energy Resource
DLMP	Distributional Locational Marginal Pricing
DR	Demand Response
DSO	Distribution System Operator
e-Directive	Directive on common rules for the internal market for electricity
e-Regulation	Regulation on the internal market for electricity
EB GL	Electricity Balancing Guideline
EC	European Commission
ERCOT	Electric Reliability Council of Texas
ETPA	Energy Trading Platform Amsterdam
FCA GL	Forward Capacity Allocation Guideline
GOPACS	Grid Operators Platform for Congestion Solutions
IDCONS	Intraday Congestion Spread
MS	Member State
NEISO	New England Independent System Operator
NRA	National Regulatory Authority

NYISO	New York Independent System Operator
P2P	Peer-to-Peer
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PX	Power Exchange
REC	Renewable Energy Community
REDII	The revised Renewable Energy Directive (EU) 2018/2001
RES	Renewable Energy Resources
RfG NC	Requirements for Generators Network Code
TSO	Transmission System Operator
UKPN	UK Power Networks
USEF	Universal Smart Energy Framework
XBID	Cross-Border Intraday Market Project

Executive Summary

This deliverable consists of two parts: the identification of new research domains which will be explored throughout the project and a first illustration of the research methodology applied to a concrete research topic, being flexibility markets.

First, in Section 2, we list five research domains in which the Clean Energy Package (CEP) allows for the implementation of national regulatory frameworks to be set up. These five domains were identified through research and teaching about the CEP and the existing network codes. The idea is that innovation with regulation at Member State level, guided by the e-Directive, can serve as inspiration for new network codes or guidelines or for amendments of existing ones. The identified research domains are:

- Flexibility Mechanisms

- Consumer Data Management

- Framework for Aggregators

- Peer-to-peer and Community-based Energy Trade

- Electro-mobility

Table 1 gives an overview of the identified research domains. Per domain, the relevant articles in the CEP, the relevant network code areas and potential research topics are included. The research topics listed below are a non-exhaustive collection of gaps or disputed issues in the current regulation at Member State or European-level related to the respective research domain.

Table 1: Overview of identified research domains ('State of play matrix')

New research domain	**Relevant CEP articles (most important in bold)**	**Relevant network code areas**	**Potential research topics (non-exhaustive)**
Flexibility mechanisms	E-Directive, Art. **32** E-Regulation, Art. 18, 30, 51, 57	E-Regulation, Art. 13(1-3,5,7), 59.1(a-e) and 59.2(b)	- Market-based procurement of flexibility for distribution grids ('flexibility markets') - Smart connection agreements - TSO-DSO cooperation, including exchange of and access to relevant data
Consumer Data Management	E-Directive, Art. 3, 13, 15, 17,20, **23-24**, 34, 59 E-Regulation, 30, 51	E-Regulation, Art. 59.1(e) and 59.2(b)	- Level of harmonisation of data management models and/or data exchange processes - Scope and interoperability of data exchange platforms - Level of access to consumer data
Framework for Aggregators	E-Directive, Art. **13**, **17**	E-Regulation, Art. 59.1(c-e) and 59.2(a)	- Baselines methodologies for aggregators - Market rules between aggregators and suppliers
Peer-to-peer and Community-based Energy Trade	E-Directive, Art. **15**-16 REDII, Art. **21**-22	E-Regulation, Art. 59.1(e) and 59.2(a,c)	- Regulation around metering of consumers with multiple energy supply contracts - Roles of responsibilities of alternative energy suppliers (e.g. community, P2P exchange,..) versus traditional retailer - The market design and transparency requirements of P2P exchanges
Electro-mobility	E-Directive, **33**	E-Regulation, Art. 59.1(c-e) and 59.2(a,c)	- Electro-mobility energy and grid services provision rules, incl. type of service, product definition

Second, besides the identification of new research domains, a first illustration of the research methodology which will be used throughout the INTERRFACE project (more specifically T9.4) is given. The selected research topic is market-based procurement of grid services by grid users connected to the distribution grid ('flexibility markets') within the research domain 'flexibility mechanisms'. Flexibility markets are recognised as a promising tool to make better use of existing distribution (and possibly also transmission) grids and thereby also reduce the need for grid investments.

More precisely, in Section 3, we first position flexibility markets within the typical sequence of existing electricity markets in the EU. Second, we analyse four pioneering projects implementing flexibility markets: Piclo Flex, Enera, GOPACS and NODES. To do this analysis, we develop a six-question framework based on a literature review. The questions are: (1) Is the flexibility market integrated in the existing sequence of EU electricity markets; (2) Is the flexibility market operator a third party[1]; (3) Are there reservation payments; (4) Are the products standardised; (5) Is there TSO-DSO cooperation for the organisation of the flexibility market; (6) Is there DSO-DSO cooperation for the organisation of the flexibility market. We find that all the considered flexibility markets are operated by a third party. All projects also engage with multiple DSOs in order to become the standardised platform provider. Important differences between the projects are the extent to which the flexibility markets are integrated into other markets, the use of reservation payments, the use of standardised products and the way TSO-DSO cooperation has been implemented. Table 2 gives an overview of the results of the study.

Table 2: Overview of the four projects for the six design controversies

	YES	**NO**
1. Is the flexibility market integrated in the existing sequence of EU electricity markets?	GOPACS and NODES	Piclo Flex and Enera
2. Is the flexibility market operator a third party?	All projects. GOPACS is not a market platform operator but an intermediary. Currently, the market platform is ETPA.	/
3. Is there a reservation payment?	Piclo Flex	Enera, GOPACS and NODES (all projects envision to integrate reservations)
4. Are products standardised in the flexibility market?	Piclo Flex, Enera and GOPACS (IDCONS product)	NODES
5. Is there TSO-DSO cooperation for the organisation of the flexibility market?	GOPACS (TSO and DSOs use the same intermediary). Enera and NODES (soon also the TSOs will be active).	Piclo Flex is solely a DSO platform
6. Is there DSO-DSO cooperation for the organisation of the flexibility market?	Piclo Flex (6 DSOs), GOPACS (4 DSOs), Enera and NODES (one DSO active per installation, soon more will join)	/

[1] A third party is defined as a party that does not act as a seller or buyer on the same platform that it is operating. An example is a power exchange.

1 Introduction

A multitude of articles in the Clean Energy Package (CEP) Directive on common rules for the internal market for electricity (e-Directive) guide Member States (MS) to innovate in new domains related to the electricity system.[2] In short, these articles set principles lining out the boundaries for the implementation of national regulatory frameworks. At the same time, these same new domains fall within the scope of network code areas identified in the CEP Regulation on the internal market for electricity (e-Regulation).[3] More precisely, in Art. 59 of the e-Regulation areas are described for which binding Commission Regulations can be developed. Some of the network code areas in Art. 59 were already described in the Third Energy Package, which preceded the CEP, and lay at the basis of eight network codes and guidelines which are currently in force. The new e-Regulation added some new network code areas and amended some existing ones. **The general idea is that innovation with regulation at MS-level, triggered by the e-Directive, can in the longer term serve for inspiration for new network codes or guidelines at EU-level or for amendments of existing ones.**

1.1 The identified research domains

In Section 2 of this document, we list five research domains in which the CEP allows for the implementation of national regulatory frameworks to be set up. These five domains were identified through research and teaching about the CEP and the existing network codes.[4] The domains are:

- Flexibility Mechanisms
- Consumer Data Management
- Framework for Aggregators
- Peer-to-peer and Community-based Energy Trade
- Electro-mobility

Per domain, first, we start with an introduction of the issues. Second, we give an overview of the relevant articles in the CEP. Third, we discuss which network code areas are relevant in this regard. Last, we identify concrete research topics related to the domain. **The listed research topics are a non-exhaustive collection of gaps or disputed issues in the current regulation at MS or EU-level related to the research domain.**

1.2 Research methodology

Throughout the INTERRFACE project, more specifically in T9.4 ('Foundations of new network codes'), the Florence School of Regulation will select research topics to be scrutinized. The research methodology will consist of three steps. First, we will monitor the implementation of pioneer projects or innovative regulation at MS-level. Second, we will develop an analytical framework which we then use to identify and discuss trends and differences among the pioneering projects or innovative regulations at MS-level. Third, recommendations for EU intervention through network codes will be given. Broadly, three sorts of recommendations can be given: (1) too early to regulate at EU-level; (2) EU-wide principles beyond what is described in the e-Directive, or; (3) EU-wide harmonization.

[2] Full name of the e-Directive: DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast).

[3] Full name of the e-Regulation: REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the internal market for electricity (recast)

[4] See e.g. Schittekatte et al. (2019) and Meeus and Nouicer (2018).

1.3 First application of the research methodology and relevance for other work packages in INTERRFACE

In Section 3 of this document, a first application of the research methodology is given. The research methodology is applied to a research topic within the domain 'flexibility mechanisms'. More precisely, market-based procurement of grid services by grid users connected to the distribution-level ('flexibility markets') is studied. Flexibility markets are recognised as a promising tool to make better use of existing distribution (and possibly also transmission) grids and thereby also reduce the need for grid investments.

Flexibility markets was selected as the first research topic as the findings can be of direct use for WP3 and the demos within the INTERRFACE project. More specifically, the analysis reveals which sort of design choices can be made when developing a flexibility platform and give insights into the trade-offs between the different options. In addition, the state of play matrix (Table 1) and the more detailed descriptions of the research domains give an up-to-date overview of the status of EU regulation on relevant topics for the project. Also, current and future regulatory challenges are highlighted.

2 Identified new research domains

2.1 Flexibility mechanisms

2.1.1 Introduction

More and more distributed energy resources (DERs) are getting connected to the lower-voltage electricity network. At the same time, electricity consumption at these endpoints of the grid is likely to increase due to electrification of transport (electric vehicles) and heating (heat pumps). It is clear that solely relying on investments in the distribution network to cope with these evolutions will be very expensive. Recent academic work, as well as position papers from relevant stakeholders, point out that the same developments that create network challenges are also part of the solution (CEER, 2018; Eid et al., 2016; ENTSO-E et al., 2019; IRENA, 2019; Ramos et al., 2016). Namely, distributed generation and increasingly smarter managed load, both possibly combined with storage, are flexible, i.e. they can change their need for electricity infeed/withdrawal on short notice. From the distribution network operator's point of view, flexibility can be used to defer costly network upgrades in the middle-long run and avoid renewable curtailment in the short-run. From the flexibility providers' point of view, selling flexibility to network operators can become an important additional revenue stream.

How to unlock this flexibility? The Council of European Energy Regulators (CEER) describes in its conclusion paper on 'Flexibility Use at Distribution Level' four approaches to enable distribution system operators (DSOs) to access flexibility (CEER, 2018). (1) **A rule-based approached** – imposing flexibility requirements through codes and rules; (2) **network tariffs** – designing cost-reflective network tariffs to better align the charges grid users face with the network costs they cause; (3) **connection agreements** – DSOs could reach arrangements with customers for the provision of flexibility in return for a cheaper connection; and (4) **market-based procurement** – DSOs can explicitly procure flexibility that benefits the grid services from the market(s). ENTSO-E et al. (2019) add a fifth approach, namely **technical solutions using grid assets**: reconfiguration of the grid topology to alter power flows, including reactive power flows, and achieve a more desirable system state.

An important point to be added to this discussion is that flexibility of resources connected to the distribution network can not only provide flexibility to the DSO but also can be procured by the TSO. In that respect, one requirement for the efficient use of flexibility is effective cooperation between TSOs and DSOs (Hadush and Meeus, 2018). This includes data and information exchange as well as rules on access to relevant data. In their 'TSO-DSO data management report' (CEDEC et al., 2016), the European TSO and DSO associations state that the first step should be for TSOs and DSOs to discuss and agree upon **common principles for data management in general**. A second step that is not explicitly mentioned in the report can be derived, namely agreeing upon and establishing **specific data management solutions**.

2.1.2 Clean Energy Package

In the e-Directive of the Clean Energy Package (CEP) (Art. 32), market-based procurement of flexibility by DSOs is described as an important tool to limit future grid investments costs. Also the e-Regulation (Art. 13) is relevant it requires market-based redispatch (incl. non-discriminatory participation of all types of resources such as demand and storage) and sets limits on the amount of redispatch of electricity from renewables that can be done. In addition, to ensure cost-efficient, secure and reliable network planning and operation, the e-Regulation (Art. 57) foresees the exchange of all necessary data and information between TSOs and DSOs as well as the coordinated use of demand side flexibility. In that respect, also the EU DSO entity will play important role as a mouthpiece for the interests of all DSOs. Finally, another relevant article to flexibility mechanisms is

Art. 18 of the e-Regulation in which principles for network tariff design are described in more detail. Box 1 gives an overview.

Box 1: Articles in the e-Directive and e-Regulation in the CEP relevant for flexibility mechanisms

E-Directive, Art. 32 (1-3) on incentives for the use of flexibility in distribution networks

1. Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system. In particular, the regulatory framework shall ensure that distribution system operators are able to procure such services from providers of distributed generation, demand response or energy storage and shall promote the uptake of energy efficiency measures, where such services cost-effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the distribution system. **Distribution system operators shall procure such services in accordance with transparent, non-discriminatory and market-based procedures** unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion.

2. Distribution system operators, subject to approval by the regulatory authority, or the regulatory authority itself, shall, in a transparent and participatory process that includes all relevant system users and transmission system operators, establish the specifications for the flexibility services procured and, where appropriate, standardised market products for such services at least at national level. The specifications shall ensure the effective and non-discriminatory participation of all market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation. **Distribution system operators shall exchange all necessary information and shall coordinate with transmission system operators in order to ensure the optimal utilisation of resources**, **to ensure the secure and efficient operation of the system and to facilitate market development.** Distribution system operators shall be adequately remunerated for the procurement of such services to allow them to recover at least their reasonable corresponding costs, including the necessary information and communication technology expenses and infrastructure costs.

3. The development of a distribution system shall be based on a transparent network development plan that the distribution system operator shall publish at least every two years and shall submit to the regulatory authority. The network development plan shall provide transparency on the medium and long-term flexibility services needed, and shall set out the planned investments for the next five-to-ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads, including recharging points for electric vehicles. **The network development plan shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion.**

E-Regulation, Art. 13 (1-3,5,7) on redispatching

1. The redispatching of generation and redispatching of demand response shall be based on objective, transparent and non-discriminatory criteria. It **shall be open to all generation technologies, all energy storage and all demand response**, including those located in other Member States unless technically not feasible.

2. The resources that are redispatched shall be selected from among generating facilities, energy storage or demand response **using market-based mechanisms** and shall be financially compensated. Balancing energy bids used for redispatching shall not set the balancing energy price.

3. Non-market-based redispatching of generation, energy storage and demand response may only be used where:
(a) no market-based alternative is available;
(b) all available market-based resources have been used;
(c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located; or
(d) the current grid situation leads to **congestion in such a regular and predictable way that market-based redispatching would lead to regular strategic bidding** which would increase the level of internal congestion and the Member State concerned either has adopted an action plan to address this congestion or ensures that minimum available capacity for cross-zonal trade is in accordance with Article 16(8).

[...]

5. Subject to requirements relating to the maintenance of the reliability and safety of the grid, based on transparent and non-discriminatory criteria established by the regulatory authorities, **transmission system operators and distribution system operators shall**:

(a) guarantee the capability of transmission networks and distribution networks to transmit electricity produced from renewable energy sources or high-efficiency cogeneration with minimum possible redispatching, which **shall not prevent network planning from taking into account limited redispatching where the transmission system operator or distribution system operator is able to demonstrate in a transparent way that doing so is more economically efficient and does not exceed 5 % of the annual generated electricity in installations which use renewable energy sources and which are directly connected to their respective grid,** unless otherwise provided by a Member State in which electricity from power-generating facilities using renewable energy sources or high-efficiency cogeneration represents more than 50 % of the annual gross final consumption of electricity;

(b) take appropriate grid-related and market-related operational measures in order to minimise the downward redispatching of electricity produced from renewable energy sources or from high-efficiency cogeneration;

(c) ensure that their networks are sufficiently flexible so that they are able to manage them.

[...]

7. Where non-market based redispatching is used, it shall be subject to **financial compensation by the system operator requesting the redispatching to the operator of the redispatched generation, energy storage or demand response facility except in the case of producers that have accepted a connection agreement under which there is no guarantee of firm delivery of energy.** Such financial compensation shall be at least equal to

the higher of the following elements or a combination of both if applying only the higher would lead to an unjustifiably low or an unjustifiably high compensation:
(a) additional operating cost caused by the redispatching, such as additional fuel costs in the case of upward redispatching, or backup heat provision in the case of downward redispatching of power-generating facilities using high-efficiency cogeneration;
(b) net revenues from the sale of electricity on the day-ahead market that the power-generating, energy storage or demand response facility would have generated without the redispatching request; where financial support is granted to power-generating, energy storage or demand response facilities based on the electricity volume generated or consumed, financial support that would have been received without the redispatching request shall be deemed to be part of the net revenues.

E-Regulation, Art. 57 on cooperation between DSOs and TSOs

1. Distribution system operators and transmission system operators shall cooperate with each other in planning and operating their networks. In particular, **distribution system operators and transmission system operators shall exchange all necessary information and data regarding, the performance of generation assets and demand side response, the daily operation of their networks and the long-term planning of network investments**, with the view to ensure the cost-efficient, secure and reliable development and operation of their networks.

2. Distribution system operators and transmission system operators **shall cooperate with each other in order to achieve coordinated access to resources such as distributed generation, energy storage or demand response that may support particular needs of both** the distribution system operators and the transmission system operators.

E-Regulation, Art. 51 on tasks of the EU DSO entity

1. The tasks of the EU DSO entity shall be the following: (e) **supporting the development of data management, cyber security and data protection** in cooperation with relevant authorities and regulated entities; (f) **participating in the development of network codes which are relevant** to the operation and planning of distribution grids and **the coordinated operation of the transmission networks and distribution networks pursuant to Article 59**.

2. In addition the EU DSO entity shall: (b) **cooperate with the ENTSO for Electricity and adopt best practices on the coordinated operation and planning** of transmission and distribution systems including **issues such as exchange of data between operators** and coordination of distributed energy resources.

E-Regulation, Art. 30 on tasks of the ENTSO for Electricity

1. The ENTSO for Electricity shall: […] (g) **cooperate** with distribution system operators and the EU DSO entity; (h) **promote the digitalisation** of transmission networks including deployment of smart grids, efficient real time data acquisition and **intelligent metering systems**; […] (n) **promote cyber security and data protection** in cooperation with relevant authorities and regulated entities

E-Regulation, Art. 18 (1-3, 7-8) on charges for access to networks, use of networks and reinforcement

1. **Charges applied by network operators for access to networks**, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements, **shall be cost-reflective, transparent, take into account the need for network security and flexibility and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a non-discriminatory manner**. Those charges shall not include unrelated costs supporting unrelated policy objectives.

Without prejudice to Article 15(1) and (6) of Directive 2012/27/EU and the criteria in Annex XI of that Directive the method used to determine the network charges shall neutrally support overall system efficiency over the long run through price signals to customers and producers and in particular be applied in a way which does not discriminate positively or negatively between production connected at the distribution level and production connected at the transmission level. **The network charges shall not discriminate either positively or negatively against energy storage or aggregation and shall not create disincentives for self-generation, self-consumption or for participation in demand response.** Without prejudice to paragraph 3, those charges shall not be distance-related.

2. Tariff methodologies shall reflect the fixed costs of transmission system operators and distribution system operators and shall provide appropriate incentives to transmission system operators and distribution system operators over both the short and long run, in order to increase efficiencies, including energy efficiency, to foster market integration and security of supply, to support efficient investments, **to support related research activities, and to facilitate innovation in interest of consumers in areas such as digitalisation, flexibility services and interconnection.**

3. Where appropriate, the level of the tariffs applied to producers or final customers, or both shall provide locational signals at Union level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure.

[...]

7. **Distribution tariffs shall be cost-reflective taking into account the use of the distribution network by system users including active customers.** Distribution tariffs may contain network connection capacity elements and may be differentiated based on system users' consumption or generation profiles. Where Member States have implemented the deployment of smart metering systems, regulatory authorities shall consider time-differentiated network tariffs when fixing or approving transmission tariffs and distribution tariffs or their methodologies in accordance with Article 59 of (EU) 2019/.. and, where appropriate, time-differentiated network tariffs may be introduced to reflect the use of the network, in a transparent, cost efficient and foreseeable way for the final customer.

8. Distribution tariff methodologies shall provide incentives to distribution system **operators for the most cost-efficient operation and development of their networks including through the procurement of services**. For that purpose regulatory authorities shall recognise relevant costs as eligible, shall include those costs in distribution tariffs, and may introduce performance targets in order to provide incentives to distribution system operators to increase efficiencies in their networks, including through energy efficiency, flexibility and the development of smart grids and intelligent metering systems.

2.1.3 Network Code and Guideline Areas

The use of market-based flexibility mechanisms as described in Art. 32 of the e-Directive in the CEP can be experimented with at a national level. Similarly, the responsibility to specify the details of TSO-DSO data exchange is currently conferred to the national level by the existing network codes and guidelines. In the future, however, the coordinated operation of transmission and distribution networks could likely include European-wide guidelines or rules on the use of flexibility mechanisms and related data exchange. Subject to their design and implementation, flexibility mechanisms, touch upon three network code areas as described in Art. 59(1) of the e-Regulation of the CEP are deemed relevant: **(1) Rules on demand response, including aggregation, energy storage and demand curtailment rules; (2) Capacity calculation and congestion management rules, and; (3) Rules for trading related to technical and operational provision of network access services and system balancing.** TSO-DSO cooperation to make use of flexibility implies data exchange, in that respect three additional network code areas are deemed important: **(4) Network security and reliability rules for technical transmission reserve capacity for operational network security as well as interoperability rules; (5) data exchange, settlement and transparency rules;** and **(6) sector-specific rules for cyber security aspects of cross-border electricity flows.**

The first network code area, i.e. rules on demand response, including aggregation, energy storage and demand curtailment rules, is obviously relevant as in its description in Art. 59(1) it is explicitly mentioned that this area includes the implementation of Art. 32 of the e-Directive. As the activation of flexible resources influences both grid operation and balancing of the system, coordination of and well-designed processes between TSOs and DSOs are important to avoid system disturbances. Moreover, data exchanges between system operators, market parties and, where relevant, final customers, are important to optimise the value customers can bring to different markets, including newly discussed flexibility markets. This network code area is a new area which was not present in the Third Energy Package preceding the CEP.[5]

The second and third network code areas, i.e. capacity calculation and congestion management rules, and rules for trading related to technical and operational provision of network access services and system balancing, are deemed relevant as the flexible resources connected to the distribution grid cannot only be used for congestion management at distribution-level but also for other purposes. Examples of other purposes are congestion management at transmission-level, system balancing and to balance the portfolios of Balance Responsible Parties (through the wholesale market). This is also what aimed is at in Art. 32(2) when stating '*Distribution system operators shall exchange all necessary information and shall coordinate with transmission system operators in order to ensure the optimal utilisation of resources, to ensure the secure and efficient operation of the system and to facilitate market development*'. Therefore, implementing flexibility mechanisms at DSO-level can have an impact on existing electricity markets. The relevant existing electricity markets are regulated by the CACM GL and the EB GL.[6] Therefore, these network codes areas, however not newly introduced, are relevant in this respect.

The fourth network code area, i.e. network security and reliability rules for technical transmission reserve capacity for operational network security as well as interoperability rules, is relevant as in its description in Art. 59(1a) it is explicitly mentioned that this area includes the implementation of Art. 57 of the e-Regulation on cooperation between DSOs and TSOs. Next to issues relating to network operation, rules on data exchange and operational planning data environments are included in the

[5] This is a new network code area but that does not imply that we start from scratch. Existing network codes already include provisions requiring TSO-DSO coordination, notably for data exchanges or prequalification of distribution-grid connected assets for participating in frequency services cf. SOGL.

[6] In Section 3.1 an overview of the current (typical) sequence of electricity markets in the EU is described and a market for flexibility procurement for distribution grids is positioned.

scope of such a network code. Furthermore, rules related to coordinated network security activities are included.

The fifth area, i.e. data exchange, settlement and transparency rules, includes rules on congestion management measures and is therefore of particular relevance with regard to the use of flexibility. The rules should also include ways in which the information is published, the timing of publication, and the entities responsible for handling.

The sixth area, i.e. sector-specific rules for cyber-security aspects of cross-border electricity flows, is deemed relevant as the deployment of intelligent metering systems requires the highest levels of cybersecurity and data protection. Currently, 43 different approaches to cybersecurity exist across Europe, including different roles and responsibilities, assessment of risks, sets of measures to prevent and manage crisis situations, and measures being triggered at different times (Twohig, 2019). An alignment of national practices is deemed of high importance for the secure and reliable operation of both the transmission and distribution networks. The e-Regulation clearly sees the responsibility for cyber-security and data protection as a shared task between TSOs, DSOs and regulatory authorities.

2.1.4 Possible concrete research topics

- Market-based procurement of flexibility for distribution grids ('flexibility markets')

- Smart connection agreements

- TSO-DSO cooperation, including exchange of and access to relevant data

2.2 Consumer data management

2.2.1 Introduction

Consumers have been given the right to access and share their own energy data by recent EU legislation from the Third Energy Package and the General Data Provision Regulation to the CEP. The management and the exchange of consumer data, i.e. metering and consumption data as well as data required for customer switching, demand response and other services, are essential for well-functioning retail markets. The integration of national retail markets is deemed more difficult than wholesale market integration due to differences in, *inter alia*, legislation, market models, retail processes, and data exchange procedures across Member States (MS). Academic work typically discusses specific aspects of the topic, such as governance of data management (Buchmann, 2017) or standardization of data models (Ascher and Kondzialka, 2018). Recent reports by stakeholders provide overviews of national practices with regard to data management (CEER, 2019a, 2019b; ENTSO-E, 2018a; THEMA, 2017) or data models and formats (Tractebel, 2018), or focus on specific use cases (ESGTF, 2019, 2016).

In its Impact Assessment for the Market Design Initiative, the European Commission (2016b) identifies differences in data management as possible market entry barriers for new actors. The European Commission also lists three options for **future data management models**: (i) **sole responsibility by the MS**, (ii) **common criteria and principles** and (iii) a **common EU model**. A common EU model was assessed by the European Commission to have high implementation costs, thus reducing the efficiency of the option. Rather, common criteria and principles are seen as the most suitable way forward.

2.2.2 Clean Energy Package

TSOs and DSOs share the view that no one-size-fits-all data management model is applicable in all European countries (ENTSO-E et al., 2016). Yet, while there is widespread agreement that the best solution for managing consumer data must be assessed for each national context, it is acknowledged that a lack of standardisation and interoperability can pose barriers to retail competition. The need for interoperable solutions is also reflected in the provisions of the CEP as shown in Box 2 below.

Box 2: Articles in the e-Directive in the CEP relevant for consumer data management

E-Directive, Art. 23 on data management

1. When laying down the rules regarding the management and exchange of data, **Member States or, where a Member State has so provided, the designated competent authorities shall specify the rules on the access to data of the final customer by eligible parties** in accordance with this Article and the applicable Union legal framework. For the purpose of this Directive, **data shall be understood to include metering and consumption data as well as data required for customer switching, demand response and other services**.

2. **Member States shall organise the management of data in order to ensure efficient and secure data access and exchange, as well as data protection and data security**. Independently of the data management model applied in each Member State, the parties responsible for data management shall provide access to the data of the final customer to any eligible party, in accordance with paragraph 1. Eligible parties shall have the requested data at their disposal in a non-discriminatory manner and simultaneously. Access to data shall be easy and the relevant procedures for obtaining access to data shall be made publicly available.

3. The rules on access to data and data storage for the purpose of this Directive shall comply with the relevant Union law. The processing of personal data within the framework of this Directive shall be carried out in accordance with Regulation (EU) 2016/679.

4. **Member States** or, where a Member State has so provided, the designated competent authorities, **shall authorise and certify or, where applicable, supervise the parties responsible for the data management**, in order to ensure that they comply with the requirements of this Directive.

5. No additional costs shall be charged to final customers for access to their data or for a request to make their data available. **Member States shall be responsible for setting the relevant charges for access to data by eligible parties**. Member States or, where a Member State has so provided, the designated competent authorities shall ensure that **any charges imposed by regulated entities that provide data services are reasonable and duly justified**.

E-Directive, Art. 24 on interoperability requirements and procedures for access to data

1. In order to promote competition in the retail market and to avoid excessive administrative costs for the eligible parties, **Member States shall facilitate the full interoperability of energy services within the Union**.

2. The **Commission shall adopt, by means of implementing acts, interoperability requirements and non-discriminatory and transparent procedures for access to data referred to in Article 23(1).** Those implementing acts shall be adopted in accordance with the advisory procedure referred to in Article 68(2).

3. Member States shall ensure that electricity undertakings apply the interoperability requirements and procedures for access to data referred to in paragraph 2. **Those requirements and procedures shall be based on existing national practices**.

E-Directive, Art. 3 on competitive, consumer-centred, flexible and non-discriminatory electricity markets

4. **Member States shall ensure a level playing field where electricity undertakings are subject to transparent, proportionate and non-discriminatory rules, fees and treatment**, in particular with respect to balancing responsibility, access to wholesale markets, **access to data**, switching processes and billing regimes and, where applicable, licensing.

E-Directive, Art. 13 on aggregation contract

3. Member States shall ensure that **final customers are entitled to receive all relevant demand response data or data on supplied and sold electricity** free of charge at least once every billing period if requested by the customer.

E-Directive, Art. 15 on active customers

2. Member States shall ensure that **active customers are: (d) entitled to delegate to a third party** the management of the installations required for their activities, including installation, operation, **data handling** and maintenance, without that third party being considered to be an active customer

E-Directive, Art. 17 on demand response through aggregation

3. Member States shall ensure that their relevant regulatory framework contains at least the following elements; [...](c) **non-discriminatory and transparent rules and procedures for the exchange of data between market participants engaged in aggregation and other electricity undertakings** that ensure easy access to data on equal and non-discriminatory terms while fully protecting commercially sensitive information and customers' personal data;

E-Directive, Art. 20 on functionalities of smart metering systems

Where the deployment of smart metering systems is positively assessed as a result of the cost-benefit assessment referred to in Article 19(2), or where smart metering systems are systematically deployed after ... [date of entry into force of this Directive], Member States shall deploy smart metering systems in accordance with European standards, Annex II and the following requirements:
(a) the smart metering systems shall accurately measure actual electricity consumption and shall be **capable of providing to final customers information on actual time of use**. **Validated historical consumption data shall be made easily and securely available and visualised** to final customers on request and at no additional cost. **Non-validated near real-time consumption data shall also be made easily and securely available** to final customers at no additional cost, **through a standardised interface or through remote access**, **in order to support automated energy efficiency programmes, demand response and other services**;
(b) the security of the smart metering systems and data communication shall comply with relevant Union security rules, having due regard of the **best available techniques for ensuring the highest level of cybersecurity protection** while bearing in mind the costs and the principle of proportionality;
[...]
(e) if final customers request it, **data on the electricity they fed into the grid and their**

electricity consumption data shall be made available to them, in accordance with the implementing acts adopted pursuant to Article 24, through a standardised communication interface or through remote access, or to a third party acting on their behalf, in an easily understandable format allowing them to compare offers on a like-for-like basis;
[...]
For the purposes of point (e) of the first subparagraph, it shall be **possible for final customers to retrieve their metering data or transmit them to another party** at no additional cost and in accordance with their right to data portability under Union data protection rules.

E-Directive, Art. 34 on tasks of distribution system operators in data management

Member States shall ensure that all eligible parties have non-discriminatory access to data under clear and equal terms, in accordance with the relevant data protection rules. In Member States where smart metering systems have been deployed in accordance with Article 19 and where distribution system operators are involved in data management, the compliance programmes referred to in point (d) of Article 35(2) shall include specific measures in order to exclude discriminatory access to data from eligible parties as provided for in Article 23. Where distribution system operators are not subject to Article 35(1), (2) or (3), Member States shall take all necessary measures to ensure that vertically integrated undertakings do not have privileged access to data for the conduct of their supply activities.

E-Directive, Art. 59 on duties and powers of the regulatory authorities

1. The regulatory authority shall have the following duties: [...] (t) **ensuring non-discriminatory access to customer consumption data**, the **provision, for optional use, of an easily understandable harmonised format at national level for consumption data**, and **prompt access for all customers to such data pursuant to Articles 23 and 24**. [...] (x) contributing to the **compatibility of data exchange processes for the most important market processes at regional level.**

E-Regulation, Art. 30 on tasks of the ENTSO for Electricity

1. The ENTSO for Electricity shall: [...] (k) **contribute to the establishment of interoperability requirements and non-discriminatory and transparent procedures for accessing data** as provided for in Article 24 of the Directive 2019/...?; [...] (n) **promote cyber security and data protection** in cooperation with relevant authorities and regulated entities.

E-Regulation, Art. 51 on tasks of the EU DSO entity

1. The tasks of the EU DSO entity shall be the following: (e) **supporting the development of data management, cyber security and data protection** in cooperation with relevant authorities and regulated entities.

2.2.3 Network Code and Guideline Areas

The CEP confers the responsibility of organising consumer data management and specifying the rules on data access to Member States. However, the aim to facilitate full interoperability of energy services across the EU may require the adoption of European rules or guidelines. In this context, the Commission is entitled to adopt interoperability requirements and non-discriminatory and transparent procedures for access to consumer data by means of implementing acts. Two network code areas as described in Art. 59 of the e-Regulation are deemed relevant: **(1) Rules on demand**

response, including aggregation, energy storage and demand curtailment rules; and **(2) data exchange, settlement and transparency rules.**

The first area, i.e. rules in relation to demand response, including rules on aggregation, energy storage, and demand curtailment rules, is relevant as Art. 23 of the e-Directive on data management includes, *inter alia*, data for demand response and other services. Consumers are entitled to participate in all electricity markets, either independently or through aggregation. This requires easy access to data as well as non-discriminatory and transparent rules and procedures for the exchange of data between market participants engaged in aggregation. At the same time, protection of both commercially sensitive data as well as customers' personal data needs to be ensured.

The second area, i.e. data exchange, settlement and transparency rules, includes rules on congestion management measures and is therefore of particular relevance with regard to the use of demand-side flexibility. On one hand, data exchanges between consumers, market parties and system operators, are important to optimise the value consumers can bring to different markets, including newly discussed flexibility markets. On the other hand, differences in the governance as well as the technical specifics of data exchange processes may pose barriers to new entrants. Thus, interoperability of national practices for accessing and exchanging consumer data is seen as fundamental for the well-functioning retail markets. Another important aspect is to ensure secure data access and exchange as well as data protection and cyber security. The e-Regulation clearly sees the responsibility for cyber security and data protection as a shared task between TSOs, DSOs and regulatory authorities.

2.2.4 Possible concrete research topics

- Level of harmonisation of data management models and/or data exchange processes
- Scope of data exchange platforms
- Level of access to consumer data

2.3 Framework for aggregators

2.3.1 Introduction

Active participation of demand into European electricity markets and grid services has been relatively limited up to date. The European Parliament report on 'The Potential of Electricity Demand Response' estimates that broadly only 20% of the demand response (DR) potential is actually exploited (EP, 2017).[7] Meeus and Nouicer (2018) describe that only a few Member States have implemented an enabling framework for DR despite its high potential in the EU and the current EU legislation.

Important actors helping to enhance demand participation and activate the DR potential are aggregators, as emphasized by the European Commission (2016) in its impact assessment. The e-Directive defines aggregation as *'a function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market.'* An aggregator is seen as an energy service provider which can change the electricity consumption of a group of electricity consumers and provide demand-side flexibility to the grid.

Different aggregator models exist that are discussed both in stakeholder reports (NordREG, 2016) and academic literature (Bray and Woodman, 2019; Poplavskaya and De Vries, 2018). Two

[7] Demand Response (DR) is defined in the e-Directive as 'the change of electricity load by final customers from their normal or current consumption patterns in response to market signals (…)'. The normal or current consumption pattern is also called the baseline in the literature.

fundamental models can be identified. First, aggregation can be carried out by the traditional energy service provider, i.e. the electricity supplier and the aggregator are one entity. Second, aggregation services can be provided by new entrants who are not the electricity supplier, so-called independent aggregators.[8]

Aggregators are subject to ongoing debate. On the one hand, the system and cost benefit of aggregation has been widely acknowledged. Aggregators effectively reduce transaction costs and information asymmetries in the market, enabling a large number of smaller and/or distributed resources to participate. Acting as intermediaries between the retail and wholesale side in electricity markets, aggregators are identified as working as 'reverse retailers' by Glachant (2019): '*instead of selling the wholesale output to feed consumption units on the retail side, like retailers typically do, they sell the control of consumption units output to the wholesale side'.*

On the other hand, one of the key debates centres around the potential impact of independent aggregators on suppliers, particularly in relation to a supplier's demand position in the market. In practice, when consumers engage with an independent aggregator, they have one contract with the supplier and a separate one with the aggregator. Market models of independent aggregators differ based on whether the independent aggregator is also balance responsible and whether a compensation for the supplier's sourcing costs needs to be paid by the independent aggregator when shifting electricity usage. It is important to keep in mind that independent aggregators and electricity suppliers can have opposing interests due to their type of activity; the former sell flexibility while the latter sells electricity.

How to enhance aggregators' participation in electricity markets? The roles and responsibilities of aggregators and their relations to suppliers and balance responsible parties (BRPs) need to be clarified. Market rules should contribute to creating favourable conditions for aggregators supporting them to create value for the entire system, while allowing for fair and non-discriminatory competition.

2.3.2 Clean Energy Package

The CEP aims to develop a comprehensive framework for aggregators and facilitate their participation in the market, thereby increasing flexibility in the energy system. Key aspects are the reduction of entry barriers for independent aggregators and the enabling of consumer switching. At the same time, aggregators shall be balance responsible and liable to pay a compensation in certain situations. An overview of the relevant articles is given in Box 3.

Box 3: Articles in the e-Directive in the CEP relevant for aggregators

E-Directive, Art. 13(1-4) on Aggregation contract

1. Member States shall ensure that all customers are **free to purchase and sell electricity services, including aggregation, other than supply, independently from their electricity supply contract** and from an electricity undertaking of their choice.

2. Member States shall ensure that, where a final customer wishes to conclude an **aggregation contract, the final customer is entitled to do so without the consent of the final customer's electricity undertakings**. Member States shall ensure that market participants engaged in aggregation fully inform customers of the terms and conditions of the contracts that they offer to them.

[8] An 'independent aggregator' is defined in the e-Directive as 'a market participant engaged in aggregation who is not affiliated to the customer's supplier.'

3. Member States shall ensure that final customers are entitled to receive all relevant demand response data or data on supplied and sold electricity free of charge at least once every billing period if requested by the customer.

4. Member States shall ensure that the rights referred to in paragraphs 2 and 3 are granted to final customers in a non-discriminatory manner as regards cost, effort or time. In particular, Member States shall ensure that customers are not subject to discriminatory technical and administrative requirements, procedures or charges by their supplier on the basis of whether they have a contract with a market participant engaged in aggregation.

E-Directive, Article 17(1-5) on Demand response through aggregation

1. Member States shall allow and foster participation of demand response through aggregation. Member States shall allow final customers, including those offering demand response through aggregation, **to participate alongside producers in a non-discriminatory manner in all electricity markets.**

2. Member States shall ensure that transmission system operators and distribution system operators, when **procuring ancillary services, treat market participants engaged in the aggregation of demand response in a non-discriminatory manner alongside producers on the basis of their technical capabilities.**

3. Member States shall ensure that their relevant regulatory framework contains at least the following elements:
(a) the right for each market participant engaged in aggregation, including independent aggregators, to enter electricity markets without the consent of other market participants;
(b) non-discriminatory and transparent rules that clearly assign roles and responsibilities to all electricity undertakings and customers;
(c) non-discriminatory and transparent rules and procedures for the exchange of data between market participants engaged in aggregation and other electricity undertakings that ensure easy access to data on equal and non-discriminatory terms while fully protecting commercially sensitive information and customers' personal data;
(d) **an obligation on market participants engaged in aggregation to be financially responsible for the imbalances that they cause in the electricity system**; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/...+ ;
(e) provision for final customers who have a contract with independent aggregators not to be subject to undue payments, penalties or other undue contractual restrictions by their suppliers;
(f) a conflict resolution mechanism between market participants engaged in aggregation and other market participants, including responsibility for imbalances.

4. **Member States may require electricity undertakings or participating final customers to pay financial compensation to other market participants or to the market participants' balance responsible parties, if those market participants or balance responsible parties are directly affected by demand response activation**. Such financial compensation shall not create a barrier to market entry for market participants engaged in aggregation or a barrier to flexibility. In such cases, the financial compensation shall be strictly limited to covering the resulting costs incurred by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response. The method for calculating compensation may take account of the benefits brought about by the independent aggregators to other market participants and, where it does so, the aggregators or participating customers may be required to contribute to such compensation but only where and to the extent that the benefits to all suppliers, customers and their balance responsible parties do not exceed the direct costs incurred. The calculation

method shall be subject to approval by the regulatory authority or by another competent national authority.

5. Member States shall ensure that regulatory authorities or, where their national legal system so requires, transmission system operators and distribution system operators, acting in close cooperation with market participants and final customers, establish the technical requirements for participation of demand response in all electricity markets on the basis of the technical characteristics of those markets and the capabilities of demand response. Such requirements shall cover participation involving aggregated loads.

2.3.3 Network Code and Guideline Areas

Rules for aggregation are not explicitly mentioned within the network codes. However, among the network codes areas listed in article 59 of the e-Regulation, four areas are deemed relevant for aggregators: **(1) rules for trading related to technical and operational provision of network access services and system balancing; (2) rules for non-discriminatory, transparent provision of non-frequency ancillary services; (3) rules for demand response, including rules on aggregation, energy storage, and demand curtailment rules;** and **(4) network connection rules.**

The first and second network code areas, i.e. rules on system balancing and non-frequency ancillary services are relevant for aggregators to clarify their roles regarding grid services. Currently, the electricity balancing guideline (EB GL) sets out rules defining the roles of balancing service providers and of balance responsible parties with the aim to ensure adequate competition based on a level-playing field between market participants, including DR aggregators and assets located at the distribution level. In the future, these rules could be amended to include more detailed rules on specific grid services provided by independent aggregators. The second network code area on non-frequency ancillary services has not been yet developed in a network code or guideline as it is a new area introduced by the e-Regulation.

The third network code area, i.e. rules on demand response, including aggregation, energy storage and demand curtailment rules, is the most relevant for DR and aggregation, where participation rules should be defined, as well as specific rules between aggregators and suppliers. Moreover, the e-Regulation foresees in recital (7e) that ''*[...] All market participants should be financially responsible for imbalances they cause in the system, representing the difference between the allocated volume and the final position in the market. For demand response aggregators, the allocated volume is made of the energy volume physically activated by the participating consumers' load, based on a defined measurement and baseline methodology*.' A future network code on DR could thus set out more detailed rules on how to measure the difference between the allocated and the eventually delivered volume.

The fourth network area is also relevant for aggregators. The current network code on Demand Connection (DC NC) lays out provision for active power and frequency control for demand units used by a demand facility or a closed distribution system to provide DR services to relevant system operators and relevant TSOs, either individually or commonly as part of demand aggregation through a third party. With increasing DR volumes participating in the electricity markets, these rules may need to be amended to better adhere to system needs.

2.3.4 Possible concrete research topics

- Baselines methodologies for aggregators

- Market rules between aggregators and suppliers

2.4 Peer-to-peer and community-based energy trade

2.4.1 Introduction

With the ongoing technological innovation (photovoltaic panels, batteries, smart metering...), the numbers of consumers with options to actively manage their load and produce electricity behind their meters is increasing exponentially. Such type of consumers is called 'active consumers'. Active consumers are defined in the e-Directive of the CEP as '*a final customer, or a group of jointly acting final customers, who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity*.' Until today, practice and research has mostly focussed on the business case of a 'classic prosumer', who uses his behind-the-meter installed DER technology to self-consume (Luthander et al., 2015; Schittekatte, 2019). Recently, also new types of interactions between active consumers started to emerge, allowing them to unite in communities or exchange energy peer-to-peer.

First, the concept of collectively owned DER assets by a group of individuals which are members of so-called Citizen energy communities (CECs) is gaining importance. CECs are defined in the e-Directive as '*legal entity that: (a) is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises; (b) has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits; and (c) may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders*'. CECs can be real physical microgrids with close proximity of the members to the DER assets or they can be virtual with dispersed members over a larger region such as an energy cooperative like Ecopower in Belgium.[9] When community members use collectively owned assets to source (part of) their electricity needs, an internal accounting system, tracking the energy exchanges, will need to be developed. Recently, also academic papers addressed collective self-consumption through communities. For example, Barbour et al. (2018) find that community batteries are more effective for distributed PV integration than individual batteries and Abada et al. (2018) show how the formation of (physical) energy communities is a function of the profit sharing rule between the members of communities and distribution network tariff design.

Second, there is also the option that DER assets are individually owned and installed behind-the-meter but that part of the self-generated energy is traded Peer-to-Peer (P2P) to other members of the P2P exchange.[10] Peer-to-peer trading of renewable energy is defined in Renewable Energy Directive (REDII) as '*the sale of renewable energy between market participants by means of a contract with pre-determined conditions governing the automated execution and settlement of the transaction, either directly between market participants or indirectly through a certified third-party market participant, such as an aggregator. The right to conduct peer-to-peer trading shall be without prejudice to the rights and obligations of the parties involved as final customers, producers, suppliers or aggregators.*' Shipworth et al. (2019) describes that one class of technology facilitating such a vision is distributed ledgers, also called blockchains. In practice, a consumer participating in such type of

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[9] According to the CEP, in a Citizen energy communities (CECs) the members and DER assets can be located physically near but not necessarily. If there is proximity and all electricity generation assets are renewable, the CEC is a Renewable energy communities (REC). However, RECs are not always a subgroup of CECs as RECs can also engage in the collective investment in other energy carriers, e.g. renewable gas, while CECs are limited to electricity.

[10] Please not that also variants such as Community-to-Community energy exchanges are possible as described in Sousa et al. (2019).

local trade will have a contract with a supplier and a separate contract with the P2P exchange. Sousa et al. (2019) explain that start-ups have emerged from R&D projects to address P2P energy trading by focusing on two business areas: (i) P2P exchange of energy surplus, where prosumers can exchange the energy surplus with their neighbours, for example through the companies – LO3 Energy SonnenCommunity, Hive Power, OneUp, Power Ledger; (ii) Energy provision/matching, where prosumers can directly choose local renewable generation, for example through the companies - Vandebron, Electron, Piclo, Dajie, Powerpeers.

2.4.2 Clean Energy Package

The right to form Citizen energy communities and collectively own and operate DER is described in the e-Directive. The e-Directive establishes a framework to be further specified in national implementations. Peer-to-peer trade and Renewable energy communities are described in the Renewable Energy Directive. An overview of the relevant articles is given in Box 4.

Box 4: Articles in the e-Directive and the Renewable Energy Directive related to peer-to-peer and community-based energy trade

E-Directive, Art. 15 (1-3,5) on active consumers

1. **Member States shall ensure that final customers are entitled to act as active customers without being subject to disproportionate or discriminatory technical requirements, administrative requirements, procedures and charges, and to network charges that are not cost-reflective.**

2. Member States shall ensure that active customers are:
(a) entitled to operate either directly or through aggregation;
(b) **entitled to sell self-generated electricity,** including through power purchase agreements;
(c) entitled to participate in flexibility schemes and energy efficiency schemes;
(d) entitled to delegate to a third party the management of the installations required for their activities, including installation, operation, data handling and maintenance, without that third party being considered to be an active customer;
(e) subject to cost-reflective, transparent and non-discriminatory network charges that account separately for the electricity fed into the grid and the electricity consumed from the grid, in accordance with Article 59(9) of this Directive and Article 18 of Regulation (EU) 2019/...+, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system;
(f) financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/...+.

3. **Member States may have different provisions applicable to individual and jointly-acting active customers in their national law, provided that all rights and obligations under this Article apply to all active customers. Any difference in the treatment of jointly-acting active customers shall be proportionate and duly justified.**

[...]

5. Member States shall ensure that **active customers that own an energy storage facility:**
(a) have the right to a grid connection within a reasonable time after the request, provided that all necessary conditions, such as balancing responsibility and adequate metering, are fulfilled;
(b) are not subject to any double charges, including network charges, for stored electricity remaining within their premises or when providing flexibility services to system operators;
(c) are not subject to disproportionate licensing requirements or fees;

(d) are allowed to provide several services simultaneously, if technically feasible.

E-Directive, Art. 16 on Citizen energy communities

1. Member States shall provide an enabling regulatory framework for citizen energy communities ensuring that:
(a) **participation in a citizen energy community is open and voluntary;**
(b) members or shareholders of a citizen energy community are entitled to leave the community, in which case Article 12 applies;
(c) **members or shareholders of a citizen energy community do not lose their rights and obligations as household customers or active customers;**
(d) subject to fair compensation as assessed by the regulatory authority, relevant distribution system operators cooperate with citizen energy communities to facilitate electricity transfers within citizen energy communities;
(e) citizen energy communities are subject to non-discriminatory, fair, proportionate and transparent procedures and charges, including with respect to registration and licensing, and to transparent, non-discriminatory and cost-reflective network charges in accordance with Article 18 of Regulation (EU) 2019/...+, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system.

2. Member States may provide in the enabling regulatory framework that citizen energy communities:
(a) are open to cross-border participation;
(b) **are entitled to own, establish, purchase or lease distribution networks and to autonomously manage them subject to conditions set out in paragraph 4 of this Article;**
(c) are subject to the exemptions provided for in Article 38(2).

3. Member States shall ensure that citizen energy communities:
(a) are able to access all electricity markets, either directly or through aggregation, in a non-discriminatory manner;
(b) are treated in a non-discriminatory and proportionate manner with regard to their activities, rights and obligations as final customers, producers, suppliers, distribution system operators or market participants engaged in aggregation;
(c) are financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/...+;
(d) **with regard to consumption of self-generated electricity, citizen energy communities are treated like active customers in accordance with point (e) of Article 15(2);**
(e) are entitled to arrange within the citizen energy community the sharing of electricity that is produced by the production units owned by the community, subject to other requirements laid down in this Article and subject to the community members retaining their rights and obligations as final customers.

For the purposes of point (e) of the first subparagraph, where electricity is shared, this shall be without prejudice to applicable network charges, tariffs and levies, in accordance with a transparent cost-benefit analysis of distributed energy resources developed by the competent national authority.

4. Member States **may decide to grant citizen energy communities the right to manage distribution networks in their area of operation** and establish the relevant procedures, without prejudice to Chapter IV or to other rules and regulations applying to distribution system operators. If such a right is granted, Member States shall ensure that citizen energy communities:

(a) are entitled to conclude an agreement on the operation of their network with the relevant distribution system operator or transmission system operator to which their network is connected;
(b) **are subject to appropriate network charges at the connection points between their network and the distribution network outside the citizen energy community** and that such network charges account separately for the electricity fed into the distribution network and the electricity consumed from the distribution network outside the citizen energy community in accordance with Article 59(7);
(c) do not discriminate or harm customers who remain connected to the distribution system.

Renewable Energy Directive, Art. 21 (1-2,4) on renewable self-consumers

1. Member States shall ensure that consumers are entitled to become renewables self-consumers, subject to this Article.

2. **Member States shall ensure that renewables self-consumers, individually or through aggregators**, are entitled:
(a) **to generate renewable energy, including for their own consumption, store and sell their excess production of renewable electricity, including through renewables power purchase agreements, electricity suppliers and peer-to-peer trading arrangements,** without being subject: (i) in relation to the electricity that they consume from or feed into the grid, to discriminatory or disproportionate procedures and charges, and to network charges that are not cost-reflective; (ii) **in relation to their self-generated electricity from renewable sources remaining within their premises, to discriminatory or disproportionate procedures, and to any charges or fees;**
(b) to install and operate electricity storage systems combined with installations generating renewable electricity for selfconsumption without liability for any double charge, including network charges, for stored electricity remaining within their premises;
(c) **to maintain their rights and obligations as final consumers;**
(d) **to receive remuneration, including, where applicable, through support schemes, for the self-generated renewable electricity that they feed into the grid, which reflects the market value of that electricity and which may take into account its long-term value to the grid, the environment and society.**

[...]

4. **Member States shall ensure that renewables self-consumers located in the same building, including multi-apartment blocks, are entitled to engage jointly in activities referred to in paragraph 2 and that they are permitted to arrange sharing of renewable energy that is produced on their site or sites between themselves, without prejudice to the network charges and other relevant charges, fees, levies and taxes applicable to each renewables self-consumer.** Member States may differentiate between individual renewables self-consumers and jointly acting renewables self-consumers. Any such differentiation shall be proportionate and duly justified.

Renewable Energy Directive, Art. 22 (1-4) on Renewable energy communities

1. Member States shall ensure **that final customers, in particular household customers, are entitled to participate in a renewable energy community while maintaining their rights or obligations as final customers**, and without being subject to unjustified or discriminatory conditions or procedures that would prevent their participation in a renewable energy

community, provided that for private undertakings, their participation does not constitute their primary commercial or professional activity.

2. Member States shall ensure that **renewable energy communities** are entitled to:
(a) **produce, consume, store and sell renewable energy, including through renewables power purchase agreements;**
(b) **share, within the renewable energy community, renewable energy that is produced by the production units owned by that renewable energy community, subject to the other requirements laid down in this Article and to maintaining the rights and obligations of the renewable energy community members as customers;**
(c) access all suitable energy markets both directly or through aggregation in a non-discriminatory manner.

3. Member States shall carry out an assessment of the existing barriers and potential of development of renewable energy communities in their territories.

4. Member States shall provide an enabling framework to promote and facilitate the development of renewable energy communities. That framework shall ensure, inter alia, that:
(a) unjustified regulatory and administrative barriers to renewable energy communities are removed;
(b) **renewable energy communities that supply energy or provide aggregation or other commercial energy services are subject to the provisions relevant for such activities;**
(c) the relevant distribution system operator cooperates with renewable energy communities to facilitate energy transfers within renewable energy communities;
(d) renewable energy communities are subject to fair, proportionate and transparent procedures, including registration and licensing procedures, and cost-reflective network charges, as well as relevant charges, levies and taxes, ensuring that they contribute, in an adequate, fair and balanced way, to the overall cost sharing of the system in line with a transparent cost-benefit analysis of distributed energy sources developed by the national competent authorities;
(e) renewable energy communities are not subject to discriminatory treatment with regard to their activities, rights and obligations as final customers, producers, suppliers, distribution system operators, or as other market participants;
(f) the participation in the renewable energy communities is accessible to all consumers, including those in low-income or vulnerable households;
(g) tools to facilitate access to finance and information are available;
(h) regulatory and capacity-building support is provided to public authorities in enabling and setting up renewable energy communities, and in helping authorities to participate directly;
(i) rules to secure the equal and non-discriminatory treatment of consumers that participate in the renewable energy community are in place.

2.4.3 Network Code and Guideline Areas

Rules related to peer-to-peer and community-based energy trade are not explicitly mentioned in the network codes areas. However, among the network codes areas listed in Art. 59 of the e-Regulation, mainly three areas are deemed relevant for active customers engaged in different forms of collective self-consumption: **(1) rules for demand response, including rules on aggregation, energy storage, and demand curtailment rules; (2) network connection rules; and (3) third party access rules.**

The first network code area, i.e. rules for demand response, is relevant as DER assets used for self-consumption can also be used to provide demand response (aggregated or not). An important technology in that regard is energy storage. The way demand response and energy storage will be regulated at European-level can impact the business case for all forms of self-consumption.

The second network code area, i.e. network connection rules, is important because it is not directly clear how to categorise groups of P2P-exchanging individuals or communities within the existing categorisation in the grid connection network codes.[11] For example, microgrids with one connection point to the central grid can be seen as load from the perspective of the central grid in point of time and as generation at one another point in time.

The third network code area, i.e. third-party access rules, is relevant as access to the transmission and distribution systems and the network tariffs that have to be paid for that access can be crucial for individually acting active consumers, active consumers engaged in peer-to-peer trade, and active consumers jointly acting within energy communities.

2.4.4 Possible concrete research topics

- Regulation around metering of consumers with multiple energy supply contracts

- Roles and responsibilities of alternative energy suppliers (e.g. community, P2P exchange,..) versus traditional retailer

- The market design transparency requirements of P2P exchanges

2.5 Electro-mobility

2.5.1 Introduction

The uptake of electro-mobility, or the electrification of transport, together with the diffusion of renewable energies are among the necessary transformations of the energy systems to reach climate targets and realize the energy transition. The Commission Communication of 20 July 2016 'European Strategy for Low-Emission Mobility' highlights the need for decarbonising the transport sector and reducing its emissions (EC, 2016b). However, numerous challenges exist.

General barriers to massive deployment of electric vehicles (EVs) are the lack of charging infrastructure, the lack of trust in environmental benefits, the difficulties of raw materials supply and the limited availability of models (Biresselioglu et al., 2018). For the industry, the small size of the electro-mobility market is currently seen as the primary challenge (Donada and Perez, 2015). This is now changing due to decreasing technology costs, fostered by notably significant subsidies in different countries (Tsakalidis and Thiel, 2018).

A serious challenge is the estimated increase in electricity demand due to the expansion of electro-mobility, the electrification of heating via heat pumps, and other trends in the electricity sector. According to a recent JRC report (Tsakalidis and Thiel, 2018) on the evolution of electric vehicles in Europe, a 15% integration of electric cars among the total number of cars on European roads in 2030 would correspond to an additional electricity demand of roughly 95 TWh per year. This represents about 3% of the total electricity consumption in the EU projected for 2030. Other reports and studies even exceed this projected integration level of 15%, such as the EC report 'A European Strategy for Low-Emission Mobility' (EC, 2016b) and Thiel et al. (2016).

The main challenge, however, is deemed to be related to the changing shape of load curves, i.e. a possible increase in evening demand peaks as users charge their EVs overnight after returning home (Engel et al., 2018). Such instantaneous local increases in demand peaks may constrain the network and require significant grid investments. At the same time, subject to the existence of enabling technologies providing shift-able load and a regulatory framework valuing their flexibility, EVs and

[11] For more information about the existing categorisation within the grid connection network codes, please consult Chapter 8 in Schittekatte et al. (2019).

heat pumps are considered a potential source of demand response allowing active engagement of their owners and other electricity customers (EC, 2016c).

Will electro-mobility be a blessing or a curse for the power system? In order to obtain the former, a regulatory framework needs to be provided which allows unlocking the flexibility potential of EVs. For example, Biresselioglu et al. (2018) identify a list of challenges and barriers that need to be overcome to achieve such goal. Regarding public charging infrastructure, Meeus and Schittekatte (2018) provide a discussion on the role of the regulator when a market-based procedure or a DSO-ownership model is opted for.

2.5.2 Clean Energy Package

The integration of electro-mobility in the power system, i.e. smart charging and possibilities to provide services to grids, is only implicitly covered in the CEP. What is explicitly described in the CEP is the regulatory framework around electric charging infrastructure. More precisely, the CEP e-Directive sets a legal framework contributing to creating favourable conditions for electro-mobility. Member States shall ensure that their national regulations and market rules do not hamper the deployment and ownership of EV charging stations, clarify the role of DSOs and ensure their neutrality as well as ensure that electricity prices reflect actual demand and supply. An overview of the relevant article 33 in the CEP is given in Box 5

Box 5: Articles in the e-Directive in the CEP relevant for electro-mobility

E-Directive, Art. 33(1-4) on Integration of electro-mobility into the electricity network

1. Without prejudice to Directive 2014/94/EU of the European Parliament and of the Council, Member States shall provide the necessary regulatory framework to facilitate the **connection of publicly accessible and private recharging points to the distribution networks.** Member States shall ensure that distribution system operators cooperate on a non-discriminatory basis with any undertaking that owns, develops, operates or manages recharging points for electric vehicles, including with regard to connection to the grid.

2. **Distribution system operators shall not own, develop, manage or operate recharging points for electric vehicles**, **except where distribution system operators own private recharging points solely for their own use.**

3. By way of derogation from paragraph 2, Member States may allow distribution system operators to own, develop, manage or operate recharging points for electric vehicles, provided that all of the following conditions are fulfilled:
(a) other parties, following an open, transparent and non-discriminatory tendering procedure that is subject to review and approval by the regulatory authority, have not been awarded a right to own, develop, manage or operate recharging points for electric vehicles, or could not deliver those services at a reasonable cost and in a timely manner;
(b) the regulatory authority has carried out an ex-ante review of the conditions of the tendering procedure under point (a) and has granted its approval;
(c) the distribution system operator operates the recharging points on the basis of third-party access in accordance with Article 6 and does not discriminate between system users or classes of system users, and in particular in favour of its related undertakings.

The regulatory authority may draw up guidelines or procurement clauses to help distribution system operators ensure a fair tendering procedure.

4. Where Member States have implemented the conditions set out in paragraph 3, Member States or their designated competent authorities shall perform, at regular intervals or at least every five years, a public consultation in order to re-assess the potential interest of other

parties in owning, developing, operating or managing recharging points for electric vehicles. Where the public consultation indicates that other parties are able to own, develop, operate or manage such points, Member States shall ensure that distribution system operators' activities in this regard are phased-out, subject to the successful completion of the tendering procedure referred to in point (a) of paragraph (3). As part of the conditions of that procedure, regulatory authorities may allow the distribution system operator to recover the residual value of its investment in recharging infrastructure.

2.5.3 Network Code and Guideline Areas

Market rules for electro-mobility are not explicitly mentioned in the network code areas listed in Article 59 of the e-Directive. However, from the point of view of electro-mobility as a potential source for a demand response and the provision of grid services, five network codes areas are deemed relevant: **(1) rules for trading related to technical and operational provision of network access services and system balancing; (2) rules for non-discriminatory, transparent provision of non-frequency ancillary services; (3) rules for demand response, including rules on aggregation, energy storage, and demand curtailment rules; (4) network connection rules;** and **(5) third-party access rules.**

The first and second network code areas, i.e., rules on system balancing and non-frequency ancillary services are relevant for electro-mobility to provide extra-revenues for owners. Rules and requirements to participate in balancing markets are included in the existing EB GL and SO GL. To account for the balancing potential of demand side flexibility stemming from EVs, the relevant existing EB GL and SO GL provisions could be subject to amendment. Such amendments could concern the definition of balancing products or the requirements for frequency ancillary services. The second area on non-frequency ancillary services constitutes a new network code area introduced by the e-Regulation.

The third network code area, i.e., rules on demand response, including aggregation, energy storage and demand curtailment rules, relates to the rights of consumers to engage in all electricity markets either independently or through aggregation. EVs are a potential source for demand response through aggregation, thus fostering engagement of active customers and new intermediaries. This area also constitutes a new network code area introduced by the e-Regulation.

The fourth network area, i.e. network connection rules, is related to the question of whether EVs are classified as demand, generation or storage. Currently, large differences exist in the connection network codes with regards to these three categories. In the case of a classification of demand, the current network code on Demand Connection (DC NC) only applies to new or existing demand facilities connected at the distribution level if they provide demand response services to relevant system operators and relevant TSOs. Generation, is heavily regulated by the Requirements for Generators network code (RfG NC), starting from generation units with a maximum capacity of 0.8 kW and more. Storage devices, except for pump-storage, are currently not included in the RfG NC. With increasing numbers of EVs and battery storage devices, the exclusion of storage from network codes is likely to change.

The fifth area on third-party access rules covers charging station access as they can be given to a third-party. Thus, a transparent and non-discriminatory framework shall be established for all charging station services providers whether they are a network operator or a third-party. This would potentially impact competition.

2.5.4 Possible concrete research topics

- Electro-mobility energy and grid services provision rules, incl. type of service, product definition

3 First application: flexibility markets

This section consists out of two parts. In the first part, we give an overview of the typical sequence of existing electricity markets in the EU and position flexibility markets within the sequence. In the second part, you can find our research paper on pioneering projects implementing flexibility markets. The paper has been published as a working paper (Schittekatte and Meeus (2019)), link: http://cadmus.eui.eu/handle/1814/63066 and is submitted to the academic journal Utilities Policy (submitted on 1 August 2019). Findings of this research were also presented on the Energy Infrastructure Forum organized by the European Commission in Copenhagen on 23-24 of May 2019.

3.1 Positioning flexibility markets within the existing sequence of EU electricity

Figure 1 shows the typical sequence of existing electricity markets in the EU.[12] We group the markets in four clusters and address these clusters one by one in the following subsections. Per cluster, we also state which European regulation, in the form of network codes and guidelines, governs the market segment. Finally, in the last subsection, flexibility markets are introduced.

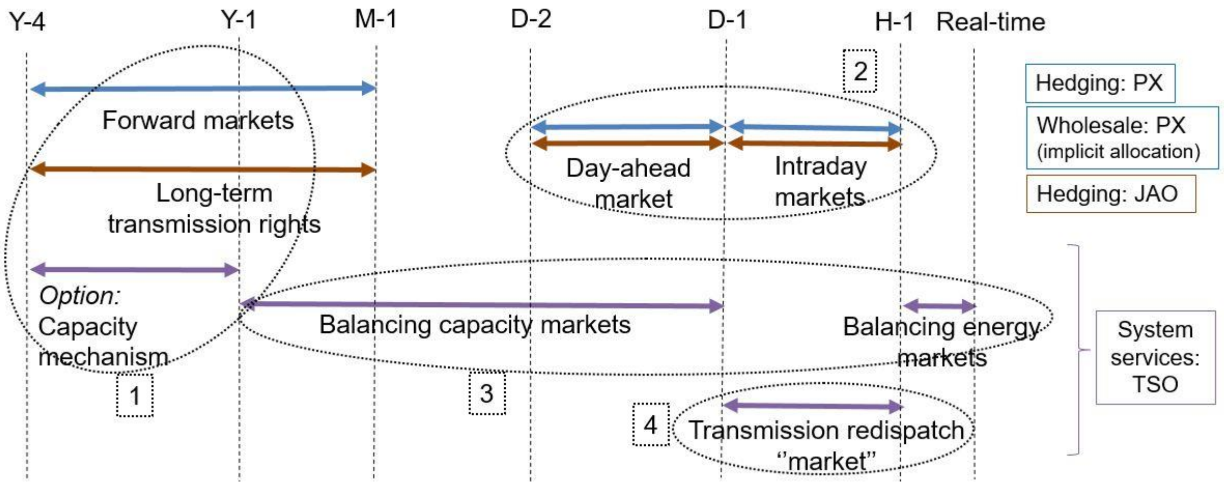

Figure 1: Schematic overview of the typical sequence of existing electricity markets in the EU. The markets are grouped into four clusters to facilitate the description.[13]

3.1.1 Long-term markets

The first cluster in Figure 1 groups the markets which are the furthest ahead of delivery. Starting from more or less 4 years up to one month before delivery, there are energy forward markets. The trades are organized by a financial exchange using standardised products (futures) or done bilaterally (forwards). The negotiated energy prices are denominated per bidding zone, which in most cases overlap with national borders.[14] If a market party wants to hedge prices across bidding zones, long-term cross-zonal transmission rights need to be acquired separately on the Joint Allocation Office (JAO) platform pursuant; this is so-called explicit allocation of transmission capacity. The platform is a joint service company of twenty TSOs. Allocation and calculation rules

[12] For a more detailed description of these different markets please consult Schittekatte et al. (2019).

[13] In this figure, with system services are meant ancillary service markets (balancing), redispatch and capacity mechanisms. Redispatch is not always organised as a market as further discussed in Section 3.1.4.

[14] A bidding zone is considered by the market as a copper plate.

around cross-zonal transmission rights are regulated by the Forward Capacity Allocation Guideline (FCA GL) (EC, 2016d).

Besides long-term energy and transmission rights markets, in the longer-term time frame, Member States can also decide to set up a capacity mechanism if deemed needed for adequacy reasons. Generally, capacity mechanisms, existing in many forms, are organised by the TSO, and the capacity procurement takes place 4 years to 1 year before delivery.

3.1.2 Wholesale markets

The second cluster in Figure 1 contains the wholesale or spot markets.[15] The day-ahead market consists of one auction at noon for the 24 hours of the next day. At the time of writing, the day-ahead market coupling project, i.e. the implicit allocation of cross-zonal transmission capacity in the energy market, is almost finalised. After the day-ahead market is cleared, the intraday market opens. Recently, ACER (2019) decided that the future intraday European model should consist of a combination of continuous trading (XBID) with three European-wide auctions at predefined times. The governance of power exchanges operating the day-ahead and intraday market, market coupling and cross-zonal intraday market design are described in the Capacity Allocation and Management Guideline (CACM GL) (EC, 2015).

3.1.3 Balancing markets

The third cluster in Figure 1 covers the balancing markets. After the intraday gate closure time, the balancing mechanism is in place to ensure that supply equals demand in real-time.[16] Each TSO is responsible for the real-time balance in its control area. To do so, each TSO organizes balancing markets where the resources needed to balance the system are procured from the balancing services providers (BSPs).[17] Balancing markets consist of balancing capacity markets and balancing energy markets. In balancing capacity markets, contracted BSPs are paid an availability payment. Contracting, one year ahead up to one day ahead, is done in order to make sure that there will always be enough balancing energy available in real-time.[18] The BSPs contracted in the balancing capacity market (as well as other BSPs without contracted balancing capacity) then offer their balancing energy in the balancing energy market, where the amount of activated energy depends on real-time imbalances. The balancing market design at the European level is prescribed in the Electricity Balancing Guideline (EB GL) (EC, 2017).

3.1.4 Transmission redispatch ''market''

Finally, the fourth cluster in Figure 1 contains the transmission redispatch market. Redispatch can be defined as the costly activation of proactive congestion relieving measures by the relevant network operator. Redispatch is needed when the market outcome (in this case the day-ahead or intraday market) results in generation and consumption schedules that would lead to a potential violation of the operating limits (e.g. thermal, voltage rating, etc.) in certain network elements within a bidding zone.[19] Such a situation occurs regularly as transmission network elements within a

[15] Please note that there is no obligation for market parties to buy and sell their energy on the spot market.

[16] Currently, the cross-zonal intraday gate closure time for the majority of borders is one hour before delivery.

[17] European platforms for imbalance netting and the different balancing energy processes (aFRR, mFRR and RR) are being implemented. This work is ongoing.

[18] Exceptionally, procurement of balancing capacity within day is also a possibility.

[19] In some Member States, besides redispatch actions just after the day-ahead market, also longer-term (month-ahead to day-ahead) forward trades or constraint management contracts can be concluded between grid users and the TSO. This is done by for example by National Grid in GB (National Grid, 2018).

bidding zone are not considered in the market coupling (so-called zonal pricing).[20] Coordinated redispatch by TSOs and cost sharing between TSOs is described in the CACM GL (EC, 2015).

In theory, all network capacity can be allocated implicitly in the wholesale market as is done only for cross-zonal transmission network elements in the EU today. Such an approach is called nodal pricing and would discard the need for TSOs to do redispatching as the market outcome would always be in line with the network capacity. The implicit allocation of all network elements is considered the first best approach to congestion management as laid out in Hogan (1992). In some US power systems (e.g. PJM, CAISO, NYISO, NEISO and ERCOT), as in New-Zealand and others, nodal pricing is applied in day-ahead and real-time.

As no nodal pricing is currently in place in the EU, transmission redispatching is widely deployed in the day-ahead and intraday timeframe.[21,22] Traditionally, generators have often been legally obliged to participate in redispatch, and prices were regulated, i.e. the audited costs (in case of upward activation) or foregone opportunity costs from the wholesale market (in case of downward activation) were paid back to the redispatched resources. Recently, with more stress on the grids due to the connection of high shares of RES and new consumption profiles, the idea to introduce market-based redispatch has gained momentum. Market-based redispatch, i.e. the abolishment of regulated prices for redispatch, is also prescribed in the CEP except under certain conditions, which include among other things the unavailability of market-based alternatives as well as situations whereby regular and predictable congestion.[23] Currently, for example, TenneT NL, the TSO in the Netherlands, does market-based procurement for redispatch (TenneT, 2019). GB and the Nordics are examples for which other arrangements are in place; in those cases, balancing and redispatch are integrated, i.e. energy offers can also be activated for redispatch purposes (ENTSO-E, 2018b).

3.1.5 Flexibility markets

Flexibility markets are not precisely defined in the existing academic literature and can take many forms. However, what all conceptualisation of flexibility markets have in common is that the main goal of the flexibility market is to allow network operators to procure flexibility services from grid users, so-called flexibility providers, connected at the distribution network. In other words, as defined in this work, flexibility markets enable (but are not excluded to) the participation of distribution-grid connected resources to market-based redispatch at the distribution-level and, depending on the implementation, also at the transmission-level. Currently, flexibility markets are not regulated in detail by network codes or guidelines at European-level. Instead, Art. 32 in the e-Directive of the CEP states that Member States shall provide the necessary regulatory framework to allow and incentivise distribution system operators to procure flexibility services.

In the recent past, there was no need to deal with congestions at the distribution level, load growth was predictable, and little generation was connected. Fit-and-forget, i.e. putting copper in the ground when needed, was the standard practice. However, with the expected increase in electrification and numerous distributed energy resources connected at distribution-level, it becomes more and more

[20] In practice, some internal transmission network elements are considered in the market coupling algorithm but not priced. However, these are only few and it is strongly recommended against including internal network elements in the market coupling by ACER (2016).

[21] Italy has a nodal design for balancing markets, while Poland is considering introducing a nodal market in all timeframes.

[22] For example, Hirth and Glismann (2018) mention that in Germany the redispatch costs were estimated to be higher than a billion euro in 2017. To reduce redispatch actions, a reconfiguration of bidding zones to better reflect structural congestion in the transmission grid is currently being debated (ENTSO-E, 2018c).

[23] See Art. 13 ‘Redispatching’ in the Regulation of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast).

expensive to rely solely on grid investment to deal with congestions. Similarly, as with nodal pricing on the transmission-level, distribution locational marginal pricing (DLMP) could be applied at distribution-level as described in the recent MIT Utility of the Future report (MIT Energy Initiative, 2016). However, in no power system in the world, DLMP is currently implemented. The main reasons are computational, administrative and institutional complexities as described in Hadush and Meeus (2018) and Neuhoff and Richstein (2017).[24] Therefore, considering the European markets are based on zonal models enabling market-based redispatch, the need for flexibility markets arose.

It should be added that both for market-based redispatch at transmission and distribution-level there is a danger for gaming, mainly if few players are active per node and structural (predictable) congestion is present.[25] Therefore, the CEP also allows for exceptions from market-based redispatch in such situations. However, it is believed that market-based redispatch can bring gains by driving redispatch costs down due to competition and can provide better price signal for where to locate future flexibility generation. Another issue with a regulated approach for redispatch is that it is very hard to estimate the costs to redispatch new generation of flexible resources such as demand response and storage. As such, these resources would be hard to deploy for such purpose, even though they could be of great value for the system. Overall, there is a trade-off between benefitting from competition and possibilities for gaming.

3.2 Flexibility markets: Q&A with project pioneers[26]

Abstract

Flexibility markets are recognised as a promising tool to make better use of existing distribution grids and thereby also reduce the need for grid investments. In this paper, we analyse four pioneering projects implementing flexibility markets: Piclo Flex, Enera, GOPACS and NODES. Based on a literature review, we develop a six-question framework and we then analyse the projects with that framework. The questions are: (1) Is the flexibility market integrated in the existing sequence of EU electricity markets; (2) Is the flexibility market operator a third party; (3) Are there reservation payments; (4) Are the products standardised; (5) Is there TSO-DSO cooperation for the organisation of the flexibility market; (6) Is there DSO-DSO cooperation for the organisation of the flexibility market. We find that all the considered flexibility markets are operated by a third party. All projects also engage with multiple DSOs in order to become the standardised platform provider. Important differences between the projects are the extent to which the flexibility markets are integrated into other markets, the use of reservation payments, the use of standardised products and the way TSO-DSO cooperation has been implemented.

Keywords: ***market design, flexibility, DSO, flexibility markets, distributed energy resources, redispatch***

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[24] Similar reasons are cited in the zonal vs nodal debate at transmission-level in the EU. The main difference is that DLMP is computationally more complex than nodal pricing due to the physics and number of network elements, see e.g. Papavasiliou (2018).

[25] Gaming in redispatch markets is further developed in the discussion of Section 3.2.3. under the discussion around reservation payments

[26] We would like to thank Sotiris Georgiopolous (UKPN), Philippe Vassilipoulous and Elies Lahmar (EPEX SPOT), Frank Wiersma (TenneT NL) and Edvard Lauen (Agder Energi) for the discussions about the respective projects. We would like to thank Elberta Ajeti, Daniel Davi-Arderius, Pablo A. Simon, Nikos Tourlis, Steve Wilkin and Peter Willis for their feedback on the FSR electricity network codes community platform on which this research was tested. We would like to thank the participants of the FSR Policy Advisory Council and the CEEM conference on the market architecture for enhancing flexibility provision for their feedback. Finally, we would like to thank Jean-Michel Glachant and Nicolò Rossetto for internal discussions.

3.2.1 Introduction

It is clear that solely relying on grid investments to cope with the increase of load and connections of decentralised generation at the distribution grid will be very expensive. In Europe, flexibility markets are recognised as a tool to make better use of the existing distribution grids and thereby also reduce the need for grid investments. Namely, the newly adopted Clean Energy Package for all Europeans states that distribution system operators shall procure services in a market-based manner from resources such as distributed generation, demand response or storage, when such services are cheaper than grid expansion.[27] Similarly, the Council of European Energy Regulators (CEER) and the respondents to its recent consultation identify market-based procurement as the preferred approach to foster the use of flexibility at the distribution grid (CEER, 2018). Finally, the European Network for Transmission System Operators for Electricity (ENTSO-E) and the major associations for European Distribution System Operators (DSOs) recently published a report in which they emphasise the need for flexibility for grids and lay out possible future active system management (ASM) techniques needed to unlock this flexibility (ENTSO-E et al., 2019).

Most of the existing literature on flexibility markets is focused on the conceptualisation of flexibility markets. In this paper, we go a step further by confronting these concepts with the actual projects that are emerging. First, we do a literature review to identify the main controversies around the design of flexibility markets, which we summarize as six yes/no questions. We illustrate that the same controversies came up in the debate around the design of other electricity markets from wholesale to balancing and re-dispatching markets. Second, we analyse the four pioneering flexibility market projects with our six-questions framework. The four projects are Piclo Flex, Enera, GOPACS and NODES.

Note finally that flexibility markets refer to peer-to-peer trading or local markets, as-well-as, to markets that are used by distribution system operators to re-dispatch their grids at distribution level. The projects referred to in this paper also illustrate how both types of trading activities can take place on the same platform. The need for re-dispatching comes from the fact that distribution constraints are not adequately taken into account in the existing wholesale and balancing markets. To the extent that this can be solved, there will be less need for flexibility markets, but that is a discussion beyond the scope of this paper. A discussion of so-called nodal pricing for distribution grids can be found in the MIT Utility of the Future report (MIT Energy Initiative, 2016) and a discussion of how zonal pricing could be implemented at distribution level can be found in Hadush and Meeus (2018).

The paper is organised as follows. In Section 2, we introduce our six-question framework. In Section 3, we analyse the four pioneering projects using the six-question framework. The six questions are: (1) Is the flexibility market integrated in the existing sequence of EU electricity markets; (2) Is the flexibility market operator a third party; (3) Are there reservation payments; (4) Are the products standardised; (5) Is there TSO-DSO cooperation for the organisation of the flexibility market; (6) Is there DSO-DSO cooperation for the organisation of the flexibility market. Per question, we first answer for each project and then provide a discussion. Finally, a conclusion is provided.

3.2.2 Six controversies around flexibility market design based on the literature and stakeholder reports

In this section, we introduce six controversies around the design of flexibility markets. These six controversies are based on a survey of existing academic literature and stakeholder reports recently published on the topic of flexibility markets. Table 3 maps the used documentation upon the six controversies. In the following of this section, we briefly discuss each controversy one by one and

[27] See Art. 32 'Incentives for the use of flexibility in distribution networks' in the Directive for the internal market in electricity (recast) (European Commission, 2019).

illustrate that the identified controversy also came up in the debate on the design of other electricity markets.[28]

Table 3: Overview of the six design controversies and mapping of relevant literature

	Academic work	Stakeholder reports
1. Is the flexibility market integrated in the existing sequence of EU electricity markets?	(Gerard et al., 2018; Ramos et al., 2016; Vicente Pastor et al., 2018; Villar et al., 2018)	(ENTSO-E et al., 2019; USEF, 2018)
2. Is the flexibility market operator a third party?	(Burger et al., 2019a; Gerard et al., 2018; Ramos et al., 2016; Stanley et al., 2019)	(ENTSO-E et al., 2019; USEF, 2018)
3. Is there a reservation payment?	(Ramos et al., 2016)	(CEER, 2018; EDSO et al., 2017; ENTSO-E et al., 2019)
4. Are products standardised in the flexibility market?	(Villar et al., 2018)	(CEER, 2018; EDSO et al., 2017; ENTSO-E et al., 2019)
5. Is there TSO-DSO cooperation for the organisation of the flexibility market?	(Brunekreeft, 2017; Burger et al., 2019a; Gerard et al., 2018; Hadush and Meeus, 2018; Le Cadre et al., 2019; Ramos et al., 2016)	(CEER, 2018; EDSO et al., 2018; ENTSO-E et al., 2019; USEF, 2018)
6. Is there DSO-DSO cooperation for the organisation of the flexibility market?	(Hadush and Meeus, 2018; Stanley et al., 2019)	/

First, flexibility of resources connected to the distribution level has multiple use cases, i.e. flexibility for the grids of network operators, for system balancing or for portfolio balancing of Balance Responsible Parties (BRPs). Different market design options are possible. ENTSO-E et al., (2019), Gerard et al. (2018), Ramos et al. (2016), USEF (2018) and Villar et al. (2018) all discuss the option to create a separate flexibility platforms for congestion management with the network operators (the DSO and possibly the TSO) as single buyers or to have a so-called integrated market model, i.e. DSOs contracting flexibility for congestion management through the existing markets (day-ahead, intraday and/or balancing). Vicente Pastor et al. (2018) do a game-theoretical analysis of the different options. Their analysis suggest that the most effective co-ordination would be regulated cooperative dispatch between all network and system operators, and a separate competitive market for BRPs. This dilemma is not completely new. For example, the balancing energy market can be integrated with the transmission redispatch market, as is the case in GB and the Nordics. Similarly, in most systems in the US and in few systems in Europe (e.g. Poland), co-optimization is applied, i.e. balancing markets and wholesale electricity markets are cleared jointly (see for example Dallinger et al. (2018) for a discussion and ENTSO-E (2018) for an overview).

Second, there is a debate about who should be the market operator. Burger et al. (2019a), Stanley et al. (2019), Ramos et al. (2016) emphasize that to ensure transparency and prevent foreclosure the market operator must maintain complete independence from market activities. Gerard et al. (2018) and USEF (2018) note that the party being the market operator will be a function of whether the

[28] For a more detailed description of these different existing electricity markets please consult Schittekatte et al. (2019).

flexibility market is separated or integrated with other markets. Finally, ENTSO-E et al. (2019) stress that network operators should act as neutral market facilitators.[29] Looking at the existing electricity markets in the EU, it can be seen that the market operator role depends on the specific market. For example, wholesale markets are operated by (third-party) power exchanges while markets for ancillary services, e.g. balancing markets, and redispatch markets are currently operated by the TSO. However, things are also moving in that regard. Namely, very recently, EPEX SPOT and National Grid joined forces to develop and operate a platform which will host a brand-new firm frequency response auction trial in Great Britain in 2019 (EPEX SPOT, 2018).

Third, there is the option to include a reservation payment. One of the possible models of flexibility markets envisioned by Ramos et al. (2016) includes long-term contracts used for assuring availability of flexibility reserves with an activation market near real-time. In that respect, CEER (2018) recognises that a lack of liquidity in flexibility markets may lead to a situation where long-term contracts may still be needed in some cases. ENTSO-E et al. (2019) describe that different situations in different Member States might require either more short or more long-term products or a combination of both. Finally, EDSO et al. (2018) note that long-term contracts are beneficial for the investment security of the flexibility providers. Again, the discussion about having reservation payments is not new. For example, balancing capacity markets are used to reserve resources for the balancing energy markets. In contrast, market players offering their resources in the wholesale market are not subject to a reservation payment.[30]

Fourth, there is a discussion about which type of products should be traded in flexibility markets, i.e. whether they should be standardized (and how) or whether flexibility providers should be allowed more freedom in characterizing their offers. Villar et al. (2018) classify flexibility products considering its main attributes such as scope, purpose, location or provider. ENTSO-E et al. (2019) recommend that product standardization is implemented at least at the Member State level to limit the costs for market participants in offering the products. EDSO et al. (2018) list up the many different product attributes that can be thought of. Besides standardizing products in a flexibility market. With the recent adoption of the recast Electricity Directive (Art. 32 (2)), such standardization of flexibility services at national level should be pursued where appropriate. In addition, there is also a discussion on whether products should be standardized on an EU-level. In that regard, CEER (2018) believes that there is no 'one-size-fits-all' approach. Also in existing electricity markets, products differ from market to market. For example, tailor-made trades can be done in bilateral (over-the-counter) markets. Also, products in wholesale markets have less strict design parameters than for example products in balancing markets.

Fifth, TSO-DSO cooperation is very much debated when discussing flexibility markets. Most academic papers, i.e. Brunekreeft (2017), Burger et al. (2019a), Gerard et al. (2018), Ramos et al. (2016), and most stakeholder reports, i.e. CEER (2018), EDSO et al. (2018), ENTSO-E et al. (2019) and USEF (2018) all discuss whether the DSO and TSO should procure flexibility in the same market. If the DSO and TSO organise the flexibility market together, more questions arise regarding whether the DSO or the TSO should have priority over flexible resources connected to the distribution grid. Also, how real-time TSO-DSO coordination should be done when a flexible resource is activated in one of the networks is undetermined for now. In that respect, Hadush and Meeus (2018) describe how TSO-DSO coordination could take inspiration from the experiences with TSO-TSO coordination for the organisation of wholesale and balancing markets. Finally, Le Cadre et al. (2019) do a game-theoretical analysis of TSO-DSO coordination. They observe that in terms of resource allocation, the centralised co-optimisation of transmission and distribution network resources are the most efficient, followed very closely by a so-called decentralised coordination scheme in which the TSO

[29] We understand under a neutral market facilitator a party that guarantees equal market access for all market parties but not necessarily a party that takes up the role of market operator.

[30] Excluding capacity mechanism which can be seen as a reservation mechanism to ensure adequacy.

and DSO simultaneously clear their local markets estimating the flows resulting from the dispatch of the DSO or TSO respectively. A third tested coordination scheme in which the DSOs act first, anticipating the behaviour of the other DSOs and the TSO, results in a lower efficiency. In most current electricity markets, both resources from the distribution and transmission-level can participate, i.e. the wholesale markets, balancing markets and even capacity mechanisms. However, in principle, all these markets could be separately organised at transmission and distribution level. For example, Burger et al. (2019a) and Gerard et al. (2018) discuss the option to have DSOs doing local balancing.

Sixth, the last identified controversy is DSO-DSO cooperation.[31] Hadush and Meeus (2018) are one of the few authors explicitly mentioning DSO-DSO cooperation. They state that the trend towards local energy systems might make DSO-DSO cooperation as important as the DSO-TSO cooperation, especially when DSOs start to use and organise flexibility markets for local congestion management. Stanley et al. (2019) note that increasingly, the aggregators of distributed flexibility and DER act across whole states, provinces and, in the future, across borders. Therefore, flexibility providers would benefit from streamlined interfaces with different DSOs. In existing markets, the focus was so far on TSO-TSO cooperation. TSO-TSO cooperation can vary to a great degree depending on the market. For example, strong TSO-TSO cooperation is in place for the day-ahead wholesale market, i.e. market coupling, while the TSO-TSO cooperation is currently less developed in balancing markets.

3.2.3 Analysing four pioneering projects

This section contains two parts. First, the four pioneering projects are introduced. Second, we go over the question per identified design controversy. Per question, we explain how each project answers the question, followed by a discussion.

3.2.3.1 Introducing the four pioneering projects

First, Piclo (previously known as Open Utility) is an independent software company that has been active in the energy industry since 2013. In October 2016, Piclo launched its first energy application, Piclo Match, a peer-to-peer energy matching service (Johnston, 2017). In this paper, we focus on Piclo's second application, namely Piclo Flex, which was launched in June 2018. Currently, six DSOs in the UK are Piclo Flex members: UK Power Networks (UKPN), Scottish and Southern Electricity Networks, Electricity North West Limited, Northern Powergrid, SP Networks and Western Power Distribution. We mainly focus on how UKPN uses Piclo to procure flexibility as UKPN is the most active Piclo Flex member to date (Stanley et al., 2019). In March 2019, the first flexibility tenders to deliver flexibility needs for 2019/20 and 2020/21 were organised by UKPN on Piclo Flex.

Second, Enera is a joint project between the power exchange EPEX SPOT, one of the German TSOs TenneT DE and the German DSOs Avacon Netz and EWE NETZ. A scalable pilot is built up in a showcase region, in this case in the windy Northwest of Germany. The main goal is to enable flexible solutions to avoid uneconomic curtailment of excess wind energy. In Enera, network operators can buy flexibility in the intraday time frame to proactively alleviate congestion.[32] The first trade was cleared on the 4th of February 2019 at 15h25. Audi (with a Power-to-Gas unit) committed to increase its consumption by 2 MW at the request of EWE NETZ for delivery on the same day from 17h00 to 18h00.

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[31] Please note that multiple configurations are possible; DSOs can be connected horizontally but also vertically.

[32] At the time of writing, in Germany, redispatch is regulated, i.e. audited cost or foregone revenues should be paid to the TSO-connected market parties which are activated for redispatch. As long as this is the case, the only way DSO-connected flexibility providers can compete to deliver flexibility to the TSO is by offering flexibility at a lower price than the costs of the TSO-connected redispatch resources.

Third, GOPACS stands for Grid Operators Platform for Congestion Solutions. GOPACS is owned and operated by the Dutch TSO and four DSOs (Stedin, Liander, Enexis Groep and Westland Infra). GOPACS is different from the other initiatives presented in this paper in the sense that it is not a market platform, i.e. no flexibility offers are cleared on GOPACS. Instead, it acts as an intermediary between the needs of network operators and markets. Currently, GOPACS is connected to a national intraday platform Energy Trading Platform Amsterdam (ETPA), which is operational in the Netherlands.[33] Offers from flexibility providers active on ETPA can be procured by GOPACS if they add a locational tag. In the near future, GOPACS intends to be connected to more market platforms.

Fourth, NODES is a joint venture between the Norwegian utility Agder Energi and the European power exchange Nord Pool. NODES was established in early 2018. Currently, NODES is active in two pilots. One installation is in place in Norway with the DSO Agder Energi Nett. Another installation is in use by the German DSO Mitnetz Strom, which is situated in the TSO area of 50Hertz. These pilots are quite different in aim as the Norwegian DSO mostly suffers from growing loads which could require an upgrade of a transformer, while the German DSO needs flexibility to avoid curtailment of renewables (USEF, 2018). On the NODES platform, balance responsible market parties (BRPs) and network operators can procure local flexibility in the intraday timeframe. The offered flexibility, which is not needed locally, will be forwarded to other existing market platforms, i.e. the intraday and balancing market. Currently, the interfaces between NODES and the existing markets are not in place yet.

3.2.3.2 Analyzing the projects on the basis of six design controversies

Is the flexibility market integrated in the existing sequence of EU electricity markets?

In this subsection, we focus on the integration of flexibility markets with wholesale and/or balancing markets. The integration of DSO flexibility markets and TSO redispatch markets is discussed in Section 3.2.5. First, we answer the question for the different projects. After, a discussion follows.

The answer of the projects to the question

In what follows we explain that there are two projects which provide separate platforms, i.e. Piclo Flex and Enera, and two projects for which the flexibility market is integrated to a certain degree in the existing sequence of markets, i.e. GOPACS and NODES.

First, Piclo Flex is clearly a separate platform from the existing sequence of electricity markets. Tenders are organised on Piclo Flex with a lead-time of six months or more, and the contract duration is between a couple of months and 4 years (UKPN, 2018). A pre-qualified flexibility provider participating in the tender has to submit both an availability offer - the price in £/MW/h for availability and a utilisation offer - the price in £/MWh for utilisation and the maximum running time (Piclo, 2019a). Contracted flexible resources on Piclo Flex do not have to adhere to dispatch instructions by the DSO for the full contracted period but only during a service window within the contracted period (e.g. winter week-day evenings), which is predetermined at the time of the tender.

Second, Enera is also a separate platform. Enera runs in the intraday timeframe. Flexibility providers submit offers and network operators submit flexibility demand orders that are continuously matched on the platform. Access to the Enera trading platform is standardized, i.e. market parties can use the same API which they use to trade in the intraday (energy) market when using EPEX SPOT's services. Market parties have the option to submit offers with the same underlying asset for the different markets. The offers can differ in price. However, if all offers on the different markets

[33] Besides intraday, ETPA offers also day ahead, week and weekend contracts.

were cleared, the activations would be incompatible. The responsibility to avoid double activation lies with the flexibility providers.

Third, GOPACS is integrated into the existing sequence of markets. The integration is achieved by sourcing flexibility from existing platforms. Currently, GOPACS is only connected to ETPA but connections with other markets are envisioned. On ETPA, locational flexibility offers for network operators are not placed on a separate platform but instead are seen as a subset of the (wholesale) intraday order book. Network operators and market parties (BRPs) can procure the same flexibility. Flexibility providers have the option to offer the same flexibility at two different prices by placing two orders, e.g. one portfolio offer for the intraday wholesale and a second offer with locational information. The flexibility provider is responsible for avoiding double activations. How GOPACS will connect the cross-zonal intraday markets and balancing markets still needs to be seen.

Fourth, NODES is integrated into the existing sequence of markets. The integration is achieved in two ways. First, NODES is an intraday platform like ETPA and similar to GOPACS, network operators source their flexibility offers on the same platform as market parties (BRPs). Again, flexibility providers can construct different offers with the same underlying assets for different prices and the flexibility provider is responsible for avoiding double activations. Second, the flexibility provided on the NODES platform, which is not needed locally, is envisioned to be forwarded to other market platforms, i.e. the cross-zonal intraday and balancing market (NODES (2018)).

Discussion

One argument in favour of separate platforms and three arguments in favour of integrated platforms are identified.

As also described in USEF (2018), the main argument to use separate platforms is that the differences between the products (locational or not) are highlighted and transparency on price levels is created.

A first argument in favour of integrated markets is liquidity pooling. However, products differ on the integrated platform (locational or not) and flexibility providers have the option to place separate offers for the same underlying assets. Note that this argument would be stronger if auctions were used instead of continuous trading (as in Enera, ETPA and NODES). With auctions, the needs of the market parties and network operators would be combined at one point in time; as such, the flexibility could be allocated more efficiently.[34]

A second argument in favour of integrated markets is the simplicity of making one platform available to which smaller market parties can connect and submit just one offer that can serve for congestion management, balancing or for a BRP to balance its portfolio. This reduces complexity and the access costs to different platforms.

A third argument in favour of integrated markets is that by allowing other market parties (BRPs) to procure locational flexibility in the same market as network operators, that market can de facto function as a secondary market for flexibility providers.

Is the flexibility market operator a third party?

First, we answer the question for the different projects. After, a discussion follows.

The answer of the projects to the question

In all four cases, a third party operates the platform. A third party is defined as a party that does not act as a seller or buyer on the same platform that it is operating.

[34] However, in case of low liquidity, there are also arguments in favor of continuous trade.

First, Piclo Flex is developed and operated by a new entrant in the energy business.

Second, in the case of Enera, EPEX SPOT built up the platform, one of the two largest power exchanges in Europe.

Third, similarly, for NODES, Nord Pool, the other large European power exchange is backing up the development. Besides Nord Pool, the other party owning NODES is Agder Energi. Agder Energi holds both distribution network assets and generation assets. In the white paper of NODES (2018), it is stated that if NODES is in full operation, it will need to be an independent party. As such, Agder Energi will not be a major owner of the marketplace.

Fourth, in the case of GOPACS, currently, the platform provider is ETPA which is a new independent power exchange. GOPACS is an intermediary between the network operators and the market platform.

Discussion

It is important to emphasize that this question is not black and white, i.e. several market operation tasks (e.g. clearing and settlement) could be allocated to third parties while other tasks could be the responsibility of the DSO (e.g. validating offers and product design). More general, three arguments in favour of having a third party as market operator are identified and one argument against.

First, in the case of DSOs, the know-how might not always be present in-house to build up market platforms from scratch. Stanley et al. (2019) points out an engagement with a specialised third party can allow for a faster development of the procurement mechanisms of new services.

Second, an argument often brought up by power exchanges is that by letting the market operation function over to a third party, neutrality between buyers and sellers is ensured. Also, in the case both DSOs and the TSO use the same platform to procure flexibility or the flexibility market is integrated in, for example, a local wholesale market, the neutrality among buyers is assured by having a third party as market operator. Burger et al. (2019a) emphasizes that neutrality is even more important if the network operator would own distributed energy resources itself (e.g. a battery).

Third, if network operators (DSO or TSO) operate the market platform for flexibility procurement, the platform will be monopolistic by nature. However, if a third party operates the platform, this is not necessarily the case. The question of whether market operation is a monopolistic activity or whether it can be a competitive activity is discussed in depth in Meeus (2011) for wholesale markets. In that paper, it is argued that due to network effects it is hard to have well-functioning competition between market platforms but that allowing competition has several advantages, for example, stronger incentives for innovation.

An argument against having a third party as a market operator is the cost of interface management between the grid operator and the market operator. There is always a cost to manage interfaces between different parties when formerly integrated activities are unbundled. Another (more extreme) example of the trade-off between removing conflicts of interest and the costs of interface management is the debate about the unbundling of TSOs or DSOs in network asset owners (TNO or DNO) and a system operator (ISO) as documented by Pollitt (2012) for TSOs and more recently debated in Burger et al. (2019b) for DSOs.

Is there a reservation payment?

First, we answer the question for the different projects. After, a discussion follows.

The answer of the projects to the question

Looking at the four projects, currently, there are only reservation payments done in Piclo Flex. An important feature of the flexibility tenders organised on Piclo Flex is that revenue stacking, i.e. contracting with multiple other services, is allowed.[35]

Enera, GOPACS and especially NODES all mention that in the future they intend to set up or integrate longer-term availability markets.

Discussion

Two arguments in favour of reservation and two arguments against reservation payments are identified.

First, long-term contracts are a way to manage the risk between the grid operator and the market parties, i.e. a guarantee that there will be flexibility at all times. An issue with services for very specific locations is that there are not necessarily many parties present that can offer the service in need. One of the possible remedies for such an issue is long-term contracts with a sufficiently long lead-time and contract duration. As such, flexibility providers are given enough time to make the necessary investments and enough certainty about future revenue streams. This is also what UKPN (2018) mentions in its Flexibility Roadmap. Namely, for reinforcement deferral (due to an increase of load), the lead-time between the tender and the start of the contract is 6 months or 18 months. Reinforcement deferral is the main use case of UKPN at this moment.[36] In the future, the lead times might be reduced significantly to, for example, one week. Currently, for example for Enera, the use case is the avoidance of curtailment, which can explain why no reservation is in place yet.

Second, long-term contracting is a way to mitigate gaming. Two types of gaming can be distinguished: gaming within a market and gaming between markets. First, as also discussed in Ramos et al. (2016), there might be moments that very few market players are able to offer flexibility at a specific location and as such, these players can make use of market power to elevate prices above competitive levels. Second, by having a wholesale electricity market with a large geographical coverage and subsequently redispatch markets at a more local level, market players can consciously create congestions by bidding in a particular way in the wholesale market and then be paid in the redispatch market to solve the problem they created themselves. This is possible under the condition that market players have a good idea of the bottlenecks in the grid. This strategy was coined as the incrementals-decrementals (inc-dec) game by Stoft (1999). Holmberg and Lazarczyk (2015) and Hirth and Schlecht (2019) show that inc-dec gaming is an arbitrage strategy that can even be successful in the absence of market power. Besides long-term contracting, there are other possible remedies to limit gaming in flexibility markets. As also discussed in Neuhoff et al. (2018), examples are: extensive (automatic) market monitoring and enforcement of anti-trust law, price caps and introducing temporary administrative prices in locations where there are few players or where structural congestion is present.[37]

[35] One exception applies, flexibility contracted on Piclo by the DSO to defer reinforcement cannot offer additional services which require an increase in active load, unless outside of contracted service windows.

[36] Other use cases are maintenance and dealing with unplanned interruptions (pre- and post-fault). Depending on the use case, the exact tender design can differ.

[37] Another way to avoid gaming is to completely regulate redispatch and remunerate instructed redispatch actions based on the audited costs or forgone revenue of the called-up resource. However, it is believed that market-based redispatch can bring gains by driving redispatch costs down due to competition and can provide better price signal for where to locate future flexibility generation or demand. Another issue with a regulated approach for redispatch is that it is very hard to estimate the costs to redispatch the new generation of flexible resources such as demand response and storage. As such, these resources would be hard to deploy for such purpose, even though they could be of great value for the system. Overall, there is a trade-off between benefitting from competition and possibilities for gaming.

A first argument against reservation payments is that short-term efficiency is sacrificed to a certain extent. However, this is only true if the utilisation payments are determined at the time of the (reservation) tender. The moment that there are enough market parties competing to offer flexibility near real-time, the requirement to determine the utilisation payment at the time of the (reservation) tender could be discarded. This is similar as is done in balancing markets in the EU. Namely, balancing capacity is procured solely based on the balancing capacity offers submitted by the Balancing Service Providers (BSPs). In real-time, there is competition for activation between contracted and non-contracted balancing resources (EC (2017), Art 16(5-6)).

A second argument against reservation payments, especially with long contract durations, is that it can be harder for certain resources due to forecasting difficulties (e.g. demand response) to guarantee availability for a long time horizon. Thus, reservation can act as an entry barrier for these flexible resources.

Are products standardised in the flexibility market?

First, we answer the question for the different projects. After, a discussion follows.

The answer of the projects to the question

For three of the projects it can be said that products are standardized, i.e. Piclo Flex, Enera and GOPACS. However, the designs of the standardized products differ substantially between the projects. Products in NODES are not standardized.

First, in Piclo Flex standardized products are in place. The short-term activation product is determined per competition area at the time of the tender. At the time of writing, UKPN has 28 competition areas defined in Piclo Flex. Besides location and voltage level, the key operational parameters are the service window (and the contract duration during which this service window holds) and the minimum and maximum running time (see also the upper left image in Figure 2). All other technical parameters are validated during the prequalification process.

Second, in Enera, standard product definitions are determined by EPEX SPOT in cooperation with the network operators procuring the flexibility. The products look similar as in the intraday, e.g. blocks of energy up or down for a certain duration (e.g. 1 hour or shorter) for a certain location as shown in the lower left image in Figure 2. In terms of locational tagging, each order belongs to a certain node predefined by Enera. In the current pilot thirteen nodes at the 110kV voltage level are defined.

Third, GOPACS, as is currently in place, procures standardized products from ETPA to which a locational tag is added. The locational tag is called an EAN-code. Unique to GOPACS is that it always procures a combination of two orders (a buy and a sell order). This product is called an Intraday Congestion Spread (IDCONS) (GOPACS, 2019). The buy and sell orders have the same format as intraday wholesale orders (simple bids of 15 minutes or 1 hour), and orders match in starting time, volume and duration but are located in a different area. The upper right image in Figure 2 illustrates the IDCONS product. For example, imagine a congestion in one part of the network due to high load. One energy sell order will be procured by GOPACS in that part of the grid. At the same time, in a non-congested area, an energy buy order will be activated. As such, an energy imbalance is avoided. The price of the energy sell order will be higher than the price of the energy buy order. The network operator who requests the flexibility pays the price difference (spread) between the orders.

Fourth, in NODES no standard product definitions are set. Instead, flexibility providers have the choice to specify their offers using a wide range of parameters. Examples are technical and financial parameters, but for example also the generation source can be specified. The lower right image in Figure 2 shows the different groups of parameters. As such, a catalogue is build up with flexibility offers. Flexibility buyers can filter offers from the catalogue and then select the cheapest offer that

fulfils their needs. NODES also allows network operators to create a template with the parameters they would like to see specified. In terms of location, flexibility offers can indicate in which grid locations (GL) they are connected. DSOs and TSOs determine the delineation of GLs, which are smaller for DSOs than TSOs and always smaller than bidding zone areas.

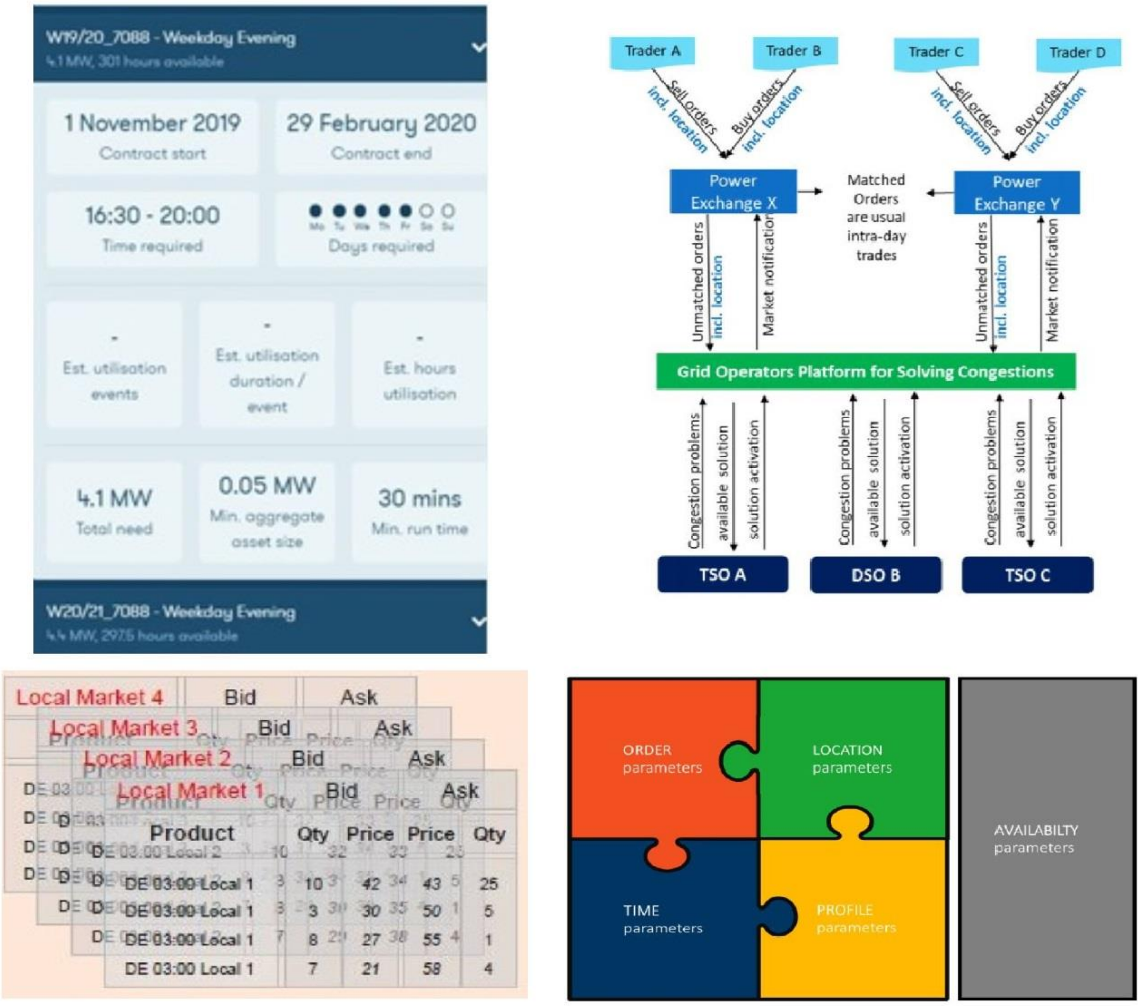

Figure 2: Illustration of the different short-term market products in Piclo Flex (service window) –upper left, Enera (locational orders) –lower left, GOPACS (IDCONS product) –upper right, and NODES (different types of parameters) –lower right. Sources: Piclo (2019b), USEF (2018), Hirth and Glismann (2018) and NODES (2018)

Discussion

We identified one argument in favour of standardized products and two against.

The main argument in favour of standardised products is to allow for a sufficient level of liquidity, i.e. standardized products allow for building up a merit order to organize competition. As a result, with standardized products price transparency is promoted. It is more difficult to compare the value of offers in case of unstandardized products. The number of different flexibility offers that can be made increases exponentially as a function of the possible product parameters.

The first argument against standardised products is that with standardised products it is hard to meet very specific flexibility needs of network operators.

A second argument against standardised products is that a catalogue approach has the advantage for flexibility providers that specific characteristics of their flexibility (e.g. reaction time or emissions) can be better valued. Flexibility providers can customize their offers and ask for premiums when an asset has valuable attributes which would otherwise not be valued if they were not part of the product definition.

Is there TSO-DSO cooperation for the organisation of the flexibility market?

First, we answer the question for the different projects. After, a discussion follows.

The answer of the projects to the question

The projects differ in how TSO-DSO cooperation is dealt with. GOPACS is built-up and used by one TSO and four DSOs. Enera and NODES allow for TSOs to procure flexibility on the same platform as DSOs but TSOs are not active yet. Piclo Flex is solely used by DSOs.

First, GOPACS is very relevant in this regard. GOPACS is one of the first implemented TSO-DSO coordination platforms. In its current version, GOPACS assures that no conflicting activations occur. In the future, the idea is also to identify synergies between the needs of different network operators.

Second, solely one DSO is procuring flexibility currently on Enera, but the TSO is expected to also become an active buyer in May 2019. In the first step of the Enera project, so-called Enera 1.0, the DSOs and the TSO are expected to communicate bilaterally when activating an offer to avoid conflicts. In the future, the idea is to have a 'vertical coupling' in place, i.e. offers will be filtered on the market platform in a way that no conflicting activation can occur, similar to how cross-zonal offers/bids are not accessible if cross-zonal links are congested in (horizontal) market coupling.

Third, currently, no TSO is active in a NODES installation. Soon the TSO will be active in the Norwegian pilot. In the future, TSO-DSO cooperation is intended to be dealt with by filtering out the offers available to one network operator if they would cause problems for other network operators. Also, the way how grid locations (GLs) are defined, which are nothing more than clusters of physical points, can help making actions of one network operator more transparent for other network operators in order to avoid conflicting activations.

Fourth, currently Piclo Flex is solely used by DSOs and the cooperation with the TSO is limited at the moment. When a DSO activates a resource for congestion management, the DSO has to notify the TSO.

Discussion

We identify three arguments in favour of TSOs and DSOs using the same platform to procure flexibility and one against.

First, fewer platforms need to be built-up and it limits the number of market platforms a flexibility provider needs to take into consideration when marketing its flexibility.

Second, liquidity increases in case TSOs and DSOs procure flexibility on the same platform, i.e. one asset connected at the distribution level can be procured by either the TSO or the DSO to solve congestions.

Third, by using the same or a similar platform, real-time coordination between the TSO and DSOs could be facilitated. Currently, real-time TSO-DSO coordination is focused on avoiding conflicting activations by the different network operators. In the future, finding synergetic activations is expected to be developed, i.e. the activation of a flexibility resource able to solve issues in both networks.

An argument against introducing a platform where both DSOs and TSOs procure flexibility is speed. It costs time to set up the collaboration with a TSO and by starting with a platform only for one or multiple DSOs initial experience can be gained.

Is there DSO-DSO cooperation for the organisation of the flexibility market?

First, we answer the question for the different projects. After, a discussion follows.

The answer of the projects to the question

All platforms are intending to engage with more DSOs in the future in order to position their (customisable) flexibility market platform as the standard solution in Europe.

First, currently six DSOs use the same platform provided by Piclo Flex. The dashboard of the platform shows all the flexibility needs of these different DSOs on one map.

Second, on Enera, currently one DSO is active, EWE NETZ. Soon, a second DSO, Avacon Netz, will become active. The case of Enera is different from Piclo Flex in the sense that DSOs are vertically connected. Namely, EWE NETZ is connected to Avacon Netz, which is in its turn connected to the TSO TenneT DE.

Third, in the case of GOPACS, four DSOs besides the TSO are using the same TSO-DSO coordination platform.

Fourth, currently, in each NODES installation solely one DSO is active. More DSOs are expected to join the platforms soon.

Discussion

Three arguments in favour of DSOs using the same platform to procure flexibility are identified and one argument against.

The first argument in favour is that when DSOs cooperate and use the same platform, the learning costs for flexibility providers with assets in different DSO areas to use the platform can be limited. This is also described by Stanley et al. (2019) who discuss the Piclo Flex platform in more depth.

Second, when DSOs use the same platform, the difficulty for the TSO to create a different TSO-DSO interface with all DSOs and other relevant companies could be reduced.[38]

Third, from an operational point of view, activations near the boundaries of two DSOs could affect each other networks if they are horizontally (or exceptionally, vertically) connected, similarly as is the case between two TSOs at the transmission level. For example, it could be that there is a congestion issue in the area of one DSO, but that cheaper flexibility that could solve that problem is available in the area of another DSO. In such a setting, coordination and cost sharing agreements between DSOs needs to be developed which are easier to develop if the same or similar flexibility platforms are used.

An argument against DSOs using the same platform to procure flexibility is that standardising the DSOs platforms to a certain extent, i.e. winner-takes-it-all, could limit benefits from innovation and competition between platform providers.

[38] An example of another company is a Balancing and Settlement Code (BSC) company which can take over some tasks of the TSO related to the imbalance settlement (e.g. as is the case in GB with Elexon).

3.2.4 Conclusion

Table 4 summarizes the answers of the four projects to our six-question framework. We can observe two trends and find four differences.

A first important trend is that all the considered platforms are operated by a third party.[39] This is relatively new in the sphere of ancillary service procurement (e.g. balancing) and redispatch where these markets are currently operated by the TSOs in the EU.

A second trend is that all projects engage or tend to engage with multiple DSOs. By doing so, the different platforms providers try to become the first-choice flexibility platform provider and become the lead player that can replicate its solution across the EU and further.

A first difference is the extent to which flexibility markets are integrated with other markets. Piclo Flex and Enera are clearly separated platforms, i.e. flexibility providers submit their locational offers and only network operators can procure this flexibility. GOPACS and NODES are integrated platforms on which both market parties (BRPs) and network operators can procure the same flexibility. Both GOPACS and NODES intend to connect to more existing electricity markets (e.g. cross-zonal intraday and balancing).

A second difference is that the projects differ in the use of reservation payments. Piclo Flex is the only one reserving flexible resources (six months or more ahead). The other platforms think about integrating availability markets but currently focus on competition in the intraday timeframe. The use of reservation payments is strongly linked with the use-case, i.e. reinforcement deferral for Piclo Flex. Also, short-term flexibility markets can provide such price signal but might need some time before the price signal is stable enough.

A third difference is related to the use of standardised products. In Piclo Flex, Enera and GOPACS standardised products are used. In contrast, NODES uses a novel approach, i.e. flexibility providers can customise their offer by specifying a multitude of parameters.

Finally, a fourth difference that can be found is the way TSO-DSO cooperation is done in the projects. Piclo Flex is a DSOs-only solution. In the other projects, DSOs and TSOs are organising the flexibility markets jointly. However, the question arises whether real-time TSO-DSO coordination should be dealt with outside of the flexibility market platform, e.g. procuring flexibility through an intermediary as with GOPACS, or whether TSO-DSO coordination should be dealt with by the flexibility market platform by filtering offers or 'vertical coupling' as it is envisioned by NODES and Enera. The border between regulated and commercial domain needs to be further discussed.

Regarding future work, it will be interesting to revisit this analysis in two to three years to see whether the answers to the six design controversies consolidated or not. Also, the first market data could be available by that time and quantitative analysis could extend this work.

[39] Different demonstrators in research projects related to flexibility marketplaces also test other approaches (e.g. TSO-led in OSMOSE, DSO-led in SmartNet, jointly TSO-DSO led in WindNode etc.). At the time of writing, these research projects are not commercialised.

Table 4: Overview of the four projects for the six design controversies

	YES	NO
1. Is the flexibility market integrated in the existing sequence of EU electricity markets?	GOPACS and NODES	Piclo Flex and Enera
2. Is the flexibility market operator a third party?	All projects. GOPACS is not a market platform operator but an intermediary. Currently, the market platform is ETPA.	/
3. Is there a reservation payment?	Piclo Flex	Enera, GOPACS and NODES (all projects envision to integrate reservations)
4. Are products standardised in the flexibility market?	Piclo Flex, Enera and GOPACS (IDCONS product)	NODES
5. Is there TSO-DSO cooperation for the organisation of the flexibility market?	GOPACS (TSO and DSOs use the same intermediary). Enera and NODES (soon also the TSOs will be active).	Piclo Flex is solely a DSO platform
6. Is there DSO-DSO cooperation for the organisation of the flexibility market?	Piclo Flex (6 DSOs), GOPACS (4 DSOs), Enera and NODES (one DSO active per installation, soon more will join)	/

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