H2020 – LC-SC3-ES-5-2018-2020
Innovation Action

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

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 824330

D9.12 Report on the Foundations for the adoptions of New Network Codes 1

Report Identifier:	D9.12		
Work-package, Task:	WP9	**Status – Version:**	1.0
Distribution Security:	CO	**Deliverable Type:**	R
Editor:	EUI		
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Reviewers:	AGEN, ENTSO-E		
Quality Reviewer:			
Keywords:	Data management, data exchange, interoperability, independent aggregators, demand-side flexibility, network codes, Clean Energy Package		
Project website: www.interrface.eu			

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BIM	Business Information Models
BSP	Balancing Service Provider
BRP	Balance Responsible Party
BRS	Business Requirement Specifications
CACM GL	Capacity Allocation and Congestion Management Guideline
CBA	Cost-Benefit Analysis
CCC	Coordinated Capacity Calculator
CCM	Capacity Calculation Methodologies
CCR	Capacity Calculation Region
CEEP	Council of European Energy Regulators
CEP	Clean Energy Package for all Europeans
CACM GL	Guideline on Capacity Allocation and Congestion Management
CGM	Common Grid Model
CGMES	Common Grid Model Exchange Specification
CGMM	Common Grid Model Methodology
CIM	Common Information Model
DA	Day-Ahead
DEP	Data Exchange Platform
DER	Distributed Energy Resources
DMM	Data Management Model
DP	Data Providers
DR	Demand Response
DSF	Demand-Side Flexibility
DSO	Distribution System Operator
ebIX	European Forum for Energy Business Information eXchange

EB GL	Electricity Balancing Guideline
EC	European Commission
ECCo SP	ENTSO-E Communication and Connectivity Service Platform
EFET	European Federation of Energy Traders
ENTSO-E	European Network of Transmission System Operators for Electricity
ESGTF	European Smart Grids Task Force
ESMP	European Style Market Profile
ESO(s)	European Standards Organizations
EU	European Union
FCA GL	Forward Capacity Allocation Guideline
FCR	Frequency Containment Reserve
GDPR	General Data Protection Regulation
GLDPM	Generation and Load Data Provision Methodology
ICE	Intercontinental Exchange
ICT	Information Communication Technology
ID	Intraday
IEC	International Electrotechnical Commission
IGM	Individual Grid Model
IL	Interruptible Load
IT	Information Technology
IGM	Individual Grid Model
KORRR	Key Organisational Requirements, Roles and Responsibilities Methodology
LLP	Licensed Load Providers
MO	Market Operator
MS	Member State of the EU
MWh	MegaWattHour
NC	Network Code

NRA	National Regulatory Authority
NTC	Net Transmission Capacity
OES	Operators of Essential Services
OPC	Outage Planning Coordination
OPDE	Operational Data Planning Environment
OPDM	Operational Planning Data Management
PCN	Physical Communication Network
PDO	Primary Data Owner
RCC	Regional Coordination Center
RDF	Resource Description Framework
SGAM	Smart Grid Architecture Model
SO GL	System Operations Guideline
ToE	Transfer of Energy
TP	Transparency Platform
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UML	Unified Modeling Language
UMM	Urgent Market Message
VoLL	Value of Lost Load
XML	Extensible Markup Language

Executive Summary

This deliverable consists of an introduction and two main parts. Each part consists of two sections:

- Data exchange and interoperability
  - Section 2.1: This section provides an in-depth description of network, market and consumer data exchange and management in Europe following requirements in the EU electricity network codes and guidelines, the Clean Energy Package and other relevant regulations like the Transparency Regulation (EU) No 543/2013.
  - Section 2.2.: This section includes a contribution with the aim to structure the debate around the ongoing preparatory work for new implementing acts on interoperability requirements and procedures for access to data following Article 24(2) of the recast of the Electricity Directive (EU) 2019/944.
- Demand-side flexibility
  - Section 3.1: This section provides an in-depth description of the regulatory framework around independent aggregators as laid out in the Clean Energy Package with a focus on balancing roles and responsibilities, including a discussion of implementations in different Member States.
  - Section 3.2: This section includes an academic study investigating the interactions between network tariff design and explicit demand-side response, in the form of mandatory curtailment by the DSO for a fixed level of compensation.

The two main topics of this interim deliverable, data exchange and interoperability and Demand-Side Flexibility (DSF), were identified as relevant research domains in the regulatory gap analysis performed in INTERRFACE Deliverable D2.4 Completed Regulatory Framework (Schittekatte et al. 2019).[1] These two topics have been listed as European priority legislations. The relevance of the network code on Demand-Side Flexibility (DSF) has been confirmed in the priority list for new network codes for 2020-2023 published on 14 October 2020 by the European Commission. The implementing act on interoperability is described as a priority action in the European Energy System Integration Strategy published in July 2020 by the European Commission. Please note that our work around flexibility market design as part of D2.4 is also very relevant with regards to the planned new network code on DSF. We chose not to include that research in this deliverable as it is already published as part of D2.4 but we plan to integrate it, possibly including some updates, in the final deliverable of T9.4.

The research results have a two-fold purpose. First, the research results feed into the ongoing discussions at national and European level around the new European legislations. Second, the research results are of direct use for the project partners who are involved in the INTERRFACE demonstrators.

Data exchange and interoperability

The two sections of this part of the deliverable cover consecutive steps of the research process, in which we explore the fundamentals in the first part and make an informed contribution to the ongoing policy and regulatory debate in the second part.

In Section 2.1, we focus on two issues related to data exchange provisions in the network codes and other relevant European legislation: the level of harmonisation of data exchange and the level of access to data. In Section 2.1.1, we introduce the Smart Grid Architecture Model (SGAM) and use it as a generic framework to discuss the level of harmonisation of data exchange processes and the related infrastructure in the European electricity sector, and we describe high-level principles

[1] INTERRFACE Deliverable D2.4 Completed Regulatory Framework is available for download at: http://www.interrface.eu/sites/default/files/publications/INTERRFACE_D2.4_v1.0.pdf.

concerning access to data. The SGAM is a three-dimensional model that is intended to present the design of smart grid use cases from an architectural, technology- and solution-neutral point of view. An important feature of the SGAM is its focus on interoperability, which is seen as the key enabler for smart grids. In Sections 2.1.2 and 2.1.3, we apply the framework to respectively network and market data, and consumer data. In both sections, we also discuss the level of access to the respective data. Table 1 maps the aspects we discuss related to network and market, and consumer data to the five interoperability layers of the SGAM framework. Harmonisation efforts can take place on every layer but full harmonisation is not always aimed for. Often national specifics and/or existing solutions need to be considered.

Table 1: Mapping of aspects we discuss related to network and market, and consumer data to the five interoperability layers of the SGAM framework

SGAM Interoperability layer	Typical aspects represented acc. to (SGCG, 2012a)	Aspects we discuss related to network and market data	Aspects we discuss related to consumer data
Business Layer	Regulatory and economic (market) structures and policies; business objectives and processes	Relevant provisions in the Third Energy Package, the Transparency Regulation and the network codes and guidelines	Relevant provisions in the Third Energy Package, Clean Energy Package and General Data Protection Regulation
Function Layer	Functions and services including their relationships	Use cases selected for the purpose of this text related to the TYNDP, the ENTSO-E Transparency Platform and the Common Grid Model for capacity calculation	Use cases and Data Management Models
Information Layer	Information objects, canonical data models	Common Information Model and harmonised data format	Interoperability requirements and data formats
Communication Layer	Communication protocols and data exchange mechanisms	ENTSO-E Communication and Connectivity Service Platform	National practices
Component Layer	Physical distribution of all participating components in a smart grid context	Physical Communication Network	

When we introduce the SGAM framework in Section 2.1, we briefly touch on the aspect of interoperability. Interoperability is of increasing importance in the European discussion around retail markets, consumer data management and the provision of energy services. Interoperability is also important on transmission and wholesale market level for the implementation of data exchange requirements stemming from the electricity network codes, the Transparency Regulation (TP) and the Ten-Year Network Development Plan (TYNDP). Interoperability is often referred to as the ability of two or more devices from the same or different vendors to exchange information and use that information for correct co-operation. It is important to keep in mind that interoperability is not the objective itself, but it is the means to the end of providing better services to energy consumers. This was recognised in the Clean Energy Package, which puts interoperability on top of the European agenda.

In Section 2.2, we focus on interoperability of energy services in Europe. The original proposal of the recast of the Electricity Directive (EU) 2019/944 in the Clean Energy Package foresaw the adoption of a common European data format for energy customer data. This was removed from the final version, which instead entitles the European Commission to adopt implementing acts specifying interoperability requirements and non-discriminatory and transparent procedures for access to data. The new acts dealing with interoperability have been established as one of three legislative priorities by the European Commission at the European Electricity Regulatory Forum ("Florence Forum") in 2019. More recently, the priority of this act was confirmed in the European Energy System Integration Strategy published in July 2020 by the European Commission. Preparatory work for the implementing acts is already ongoing. In this section of the deliverable, we elaborate on three findings.

First, different multi-dimensional interoperability frameworks exist. While they agree that full interoperability can only be achieved if all dimensions are addressed, they do not agree on either the number of dimensions or on labelling them. We do not propose an additional framework but identify commonalities across the frameworks that need to be addressed to achieve full interoperability of energy services within the Union.

Second, experience shows that different use cases can inspire different solutions. We focus on the North American Green Button initiative for utility customer data and ENTSO-E's experience in supporting network code requirements for the exchange of market and network data. Moreover, experience with interoperability in healthcare is very advanced and can serve as an inspiration for energy, especially regarding interoperability testing and governance.

Third, governance is a key issue in achieving interoperability. The existing governance mainly covers stakeholder dialogue and European standardisation. We provide ideas on how to use the EU interoperability acts to step up these efforts. In addition, we think governance should be extended to include formalisation of best practices, implementation monitoring and reporting, and interoperability testing. This governance could be taken on by a new EU entity.

Demand-side flexibility

To meet the ambitious European climate and energy objectives, Member States will have to increase the share of renewable energy sources (RES) in the electricity mix. An increasing part of these resources will be intermittent RES (wind and solar) creating periods of abundance and scarcity. Many of these resources are connected to low and medium voltage distribution networks. At the same time, increasing loads in distribution networks due to the electrification of transport (e.g. electric vehicles (EVs)) and heating (e.g. heat pumps) also give rise to challenges for DSOs. DSOs in charge of developing, maintaining, and running distribution networks will face higher demand and production peaks that need to be actively managed to minimise network costs while maintaining quality of service.

Flexibility, coming from both the supply and demand-side, is critical to face these challenges. While supply-side flexibility has been traditionally provided in electricity systems, demand-side flexibility, driven by new technological tools, is a more recent development. Demand-side flexibility can help to limit the need for network investment. Regulation and market design need to evolve to create a level playing field between demand and supply-side flexibility. This has been recognized in the Clean Energy Package, which states that enabling regulatory frameworks shall be implemented at the national level. Experiences at the national level feed discussions around the development a new European network code on demand-side flexibility or the amendment of existing network codes.[2]

[2] With "a new network code on demand-side flexibility" we refer to Art. 59(1.e) Regulation (EU) 2019/943, stating the possibility to adopt a new network code in relation to demand response, including rules on aggregation, energy storage, and demand curtailment rules.

The two sections of this part of the deliverable on demand-side flexibility focus on two important elements of the ongoing debate around the (possible) new network code on DSF: the regulatory framework around independent aggregation and the interaction between implicit and explicit demand response. The research findings in this report complement our earlier work done around the design of flexibility markets, another important topic which is part of the same debate (Schittekatte et al. 2019).

In Section 3.1, we focus on the regulatory framework around independent aggregators. Independent aggregators have been defined in the Clean Energy Package (CEP), more specifically in Art. 2 (19) of the Directive (EU) 2019/944, as *« a market participant engaged in aggregation who is not affiliated to the customer's supplier ».* 'Aggregation' is defined 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 »*. Even though independent aggregators are defined in the CEP, the implementation of their regulatory framework has not been detailed. In this section, we focus on one important element of the regulatory framework, namely on the (contractual) relationship between the independent aggregator and the supplier. We find that there is a consensus in the literature and practice about the need to correct the supplier's Balance Responsible Party (BRP) for the DR activations by the independent aggregator. However, some implementation issues remain open. In contrast, no consensus exists around the need for a compensation of the supplier for foregone energy sales. Some stakeholders argue that not enforcing a supplier compensation is a justifiable implicit subsidy for aggregators, while others point out that such practice is discriminatory and distorts competition. Most European countries with a regulatory framework for independent aggregation in place follow the latter reasoning and have implemented a compensation model. We describe three compensation models and discuss four of their properties. No model stands out; each model makes its own trade-offs. In order to facilitate cross-border aggregation, we deem that the priority should be to provide more guidance at the European level on the need for a supplier compensation over discussions about the details of the exact compensation model.

In Section 3.2 we investigate the economics of demand-side flexibility. More concretely, through a game-theoretical model, we focus on the case of mandatory curtailment by the DSO with compensation. We develop a long-term bi-level equilibrium model where the regulated DSO maximizes the social welfare while deciding on the network investment and/or consumers' curtailment for a fixed level of compensation. Consumers that can be prosumers or passive consumers react to this while fulfilling their own electricity demand. The DSO anticipates the reaction of the consumers when investing in the network and when setting the flexibility level. Furthermore, the model assesses the interaction between implicit (network tariffs) and explicit (mandatory curtailment) demand-side flexibility. Network tariffs are set to recover the network costs and flexibility costs. We find that the economics of explicit demand-side flexibility are more positive when tariffs are cost-reflective. This implies that we cannot avoid redesigning tariffs by using explicit demand flexibility. We also find that setting an appropriate level of compensation is difficult. A high level of compensation will be gamed by prosumers relying on solar PV generation and battery storage systems.

1. Introduction

A multitude of articles in the recast of the electricity Directive (EU) 2019/944 in the Clean Energy Package (CEP) guide Member States (MS) to innovate in new domains related to the electricity system. In short, these articles set principles lining out the boundaries for the implementation of national regulatory frameworks. These same new domains also fall within the scope of network code areas identified in Art. 59 of the recast of the electricity Regulation (EU) 2019/943 of the Clean Energy Package (CEP). Also, Directive (EU) 2019/944 foresees other types of acts that will not be adopted as new network codes but are likewise new European rules covering these new domains.

The general idea is that innovation with regulation at Member State-level, triggered by the provisions in Directive (EU) 2019/944, can in the longer term serve for inspiration for new network codes, guidelines or other new EU acts, or for amendments of existing ones. In this context, INTERRFACE partner FSR/EUI has developed a research frame that is described in Deliverable *D2.4 Completed Regulatory Framework* (Schittekatte et al. 2019).[3] More specifically, in that Deliverable D2.4, we list five research domains, which were identified through FSR/EUI research and teaching activities on the CEP and the electricity network codes and guidelines.[4] Note that the listed research topics are a non-exhaustive collection of gaps or disputed issues in the current regulation at Member State (MS) or EU-level related to the research domain. The originally identified research domains were:

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

The first research topic we focused on within the INTERRFACE project was flexibility markets, a subcategory of the research domain “Flexibility Mechanisms”. Flexibility markets are relevant to the discussions around a new network code in relation to demand response, including rules on aggregation, energy storage, and demand curtailment rules (Regulation (EU) 2019/943, Art. 59(1.e)). The research results can be found in Deliverable D2.4, and also resulted in an academic publication (Schittekatte and Meeus, 2020).

In this intermediate deliverable, we focus on the second and third research domains in the list.

First, we focus on the management and exchange of different types of data, i.e. network, market and consumer, as well as interoperability. In that sense, the scope of the research domain ‘’Consumer Data Management’’ has been broadened to reach beyond consumer data. Network and market data are covered not least due to their relevance for the INTERRFACE project, see also Section 1.3. This research contributes particularly to the discussions concerning the emerging EU implementing acts on interoperability. More precisely, Article 24(2) of the Directive (EU) 2019/944 entitles the European Commission to adopt implementing acts specifying interoperability requirements and non-discriminatory and transparent procedures for access to data. Data is understood to include metering and consumption data, as well as data for customer switching, demand response and other services as specified in Art. 23(1) of Directive (EU) 2019/944. Preparatory work for the new implementing act is already ongoing.

Second, we focus on two ongoing streams of research around demand-side flexibility. The first one evolves around the regulatory framework for independent aggregation, while the second deals in more depth with the economics of demand-side flexibility. In that sense, also the scope of this

[3] D2.4 is also available at http://www.interrface.eu/sites/default/files/publications/INTERRFACE_D2.4_v1.0.pdf.

[4] For more information about the Clean Energy Package and the existing EU Electricity Network Codes, please consult: Nouicer et al. (2020a) and Schittekatte et al. (2020).

research domain has been broadened. Together with the completed work on flexibility markets (see above), these streams of research form part of and feed directly into the ongoing discussion around a new network code on demand response, including rules on aggregation, energy storage, and demand curtailment rules. It is not yet clear what the scope of such network code will be, which is why we aim to lay some foundations for the ongoing discussions with the research conducted through the INTERRFACE project.

1.1 The link to the research domains identified in INTERRFACE deliverable "D2.4 Completed Regulatory Framework" and to other activities in WP9

This deliverable is part of the ongoing research activities of the Florence School of Regulation/European University Institute (FSR/EUI) in WP9 and links to the research activities in WP2. Figure 1 shows the interaction between Tasks 2.4, 9.2 and 9.4 led by FSR/EUI. Task 2.4. has set the regulatory framework for Task 9.4 and serves as input for WP3. For each research topic, the Florence School of Regulation carries out various stakeholder involvement activities in the context of Task 9.2 that inform the research carried out in Task 9.4.

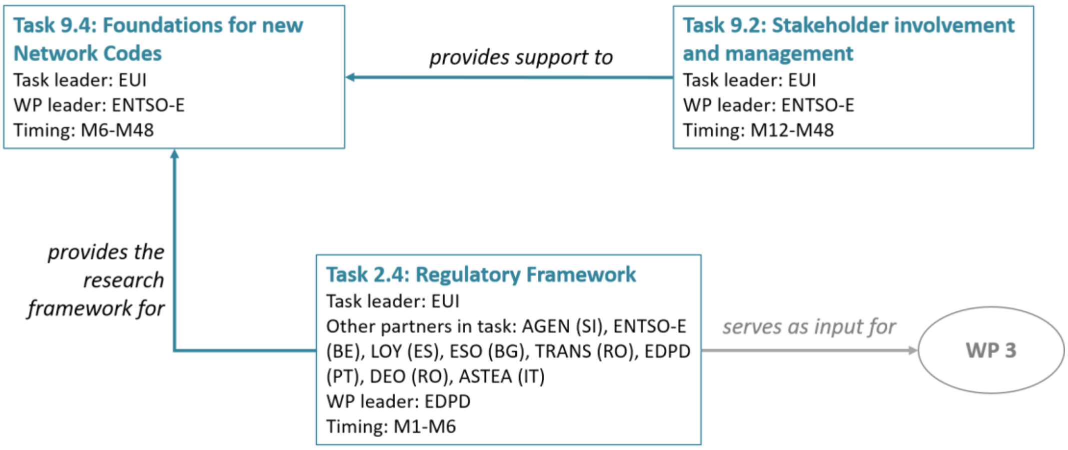


Figure 1: Interrelation between INTERRFACE tasks 2.4, 9.2 and 9.4 led by FSR/EUI

Stakeholder involvement and management is a reciprocal process between the project partners and relevant stakeholder group. On the one hand, stakeholder involvement and management are critical components of the successful delivery of any project such as INTERRFACE in its entirety. On the other hand, stakeholder engagement can also significantly drive progress in research through hands-on feedback about real-life implementation of proposed concepts and frameworks. A comprehensive description of the INTERRFACE strategy for stakeholder involvement and management is provided in Deliverable *D9.4 Yearly Exploitation Report and Business Plan Update 1*. The dissemination and stakeholder involvement activities conducted for each research topic are described in more detail below.

Data exchange and interoperability

Section 2.1 of this deliverable on network, market and consumer data and data exchange was published as a chapter of a Technical Report in July 2020 (Schittekatte et al. 2020), following a Florence School of Regulation online training on the EU electricity network codes and guidelines. In the context of the related online training, EUI/FSR also organised an online expert panel in November 2019 to discuss different elements of network, market and consumer data management and data exchange with policymakers and regulators, TSO, DSOs and the industry.

Section 2.2 of this deliverable on interoperability and the upcoming EU interoperability acts was published as an FSR Policy Brief in July 2020 (Reif and Meeus 2020). In May 2020, FSR/EUI presented the Policy Brief at the Florence School of Regulation's Policy Advisory Council (closed door event) and discussed the future pathway towards interoperability of energy services in Europe with an expert panel consisting of policymakers, regulators, industry, and other stakeholders. In July 2020, FSR/EUI organised an online debate on interoperability of energy services together with representatives of the TSOs community and industry.[5] In January 2021, FSR/EUI organised an online event in the context of the "FSR insights" series to discuss ongoing research on interoperability with an academic panel consisting of academics from other sectors.[6] In all FSR/EUI online events, the audience is typically composed of academics, TSO-DSO representatives, industry representatives, and regulators.

Demand-side flexibility

Section 3.2 was published as an FSR working paper in July 2020 (Nouicer et al. 2020b) and has been submitted to an academic peer-reviewed journal. Moreover, an online event was organised to discuss the research results with a panel of two regulators (from Flanders and Norway) who wrote a relevant CEER report on the same topic.[7] Dissemination activities regarding the work about the regulatory framework around independent aggregation are planned for 2021.

Note also that significant stakeholder engagement activities were conducted for the research topic of flexibility mechanisms and flexibility markets which is another important topic with regards to the possible new network code on Demand-Side Flexibility (DSF) (Schittekatte and Meeus, 2020). EUI/FSR organized an online debate with representatives of innovators and startups active in flexibility markets for its network of alumni. At the Florence School of Regulation's Policy Advisory Council (closed door event) a session was organised around flexibility markets featuring a panel of three regulators (from Great Britain, Slovenia and the Netherlands) to provide a regulatory perspective. The audience consisted of academics, TSO-DSO representatives, industry, policy makers and regulators. Importantly, the 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 in the session " *TSO-DSO cooperation for the future of energy infrastructure planning*". Lastly, the research was also featured in the above described online event with regulators active in CEER.

1.2 Research methodology

Throughout the INTERRFACE project, more specifically in T9.4 ('Foundations for the adoption of new network codes'), selected research topics are scrutinized. As was also described in Deliverable 2.4, the research methodology generally consists of multiple steps to address the identified research topics. The steps can differ slightly per topic.

Section 2 of this deliverable on data exchange and interoperability consists of two parts that are closely related and form two steps of the research process on the same topic.

- In Section 2.1, we explore the fundamentals by providing an in-depth description of network, market and consumer data exchange and management in Europe following requirements in the network codes and guidelines, the Clean Energy Package and other relevant regulations like the Transparency Regulation (TP) or the General Data Protection Regulation (GDPR).

[5] The recording of the online debate and a summary of the event highlights are available at https://fsr.eui.eu/event/facilitating-interoperability-of-energy-services-in-europe/.

[6] The event page is available at https://fsr.eui.eu/event/digitalization-of-energy-infrastructure-and-data-interoperability-what-can-we-learn-from-telecom-and-healthcare/.

[7] CEER Paper on DSO Procedures of Procurement of Flexibility (16 July 2020), link: https://www.ceer.eu/documents/104400/-/-/f65ef568-dd7b-4f8c-d182-b04fc1656e58 . Highlights and recording of the event: https://fsr.eui.eu/how-to-unlock-the-flexibility-potential-in-electricity-systems-a-regulatory-debate/

- In Section 2.2, we make an informed contribution to the current policy and regulatory debate and the ongoing preparatory work for new implementing acts on interoperability requirements and procedures for access to data following Art. 24(2) of the recast of the Electricity Directive (EU) 2019/944. Our contribution aims to structure the debate by highlighting three issues that likely need to be considered for the upcoming implementing acts.

Section 3 of this deliverable integrates two research streams around the topic of demand-side flexibility.

- In Section 3.1, we take stock of the regulatory framework for independent aggregators. We look at the issue of the perimeter correction and the compensation between the independent aggregator and the supplier. We describe three compensation models and discuss four of their properties. We discuss whether there is already a consensus found at EU-level regarding these discussions. The research helps to inform the debate at the European level around the need for further guidance for the framework for independent aggregation, which might be a topic covered by the new network code on demand-side flexibility.
- In Section 3.2 we go more into depth on the economics of demand-side flexibility. More concretely, through a game-theoretical model, we focus on the case of mandatory curtailment by the DSO with compensation. We develop a long-term bi-level equilibrium model where the regulated DSO maximizes the social welfare while deciding on the network investment and/or consumers' curtailment for a fixed level of compensation. We also draw recommendations for demand-side flexibility in the use case of distribution network investment savings. The results on the interaction between explicit demand-side flexibility and network tariffs contribute to the ongoing debate about the interaction between different tools to activate demand-side flexibility.

1.3 Relevance for other work packages in INTERRFACE

Data exchange, management and interoperability are core topics of the INTERRFACE project and its aim to develop an Integrated Pan-European Grid Services Architecture (IEGSA). The findings of Section 2 can inform the decisions made in WP3 on the INTERRFACE system architecture design (functional and technical). It can also serve as an input for the demos within the INTERRFACE project. More specifically, the analysis of the current status of data exchange and management in the first part (Table 1) shows how different software and hardware are currently used to manage data flows in the different parts of the electricity value chain. Also, with increasing system complexity on all levels of grid and market operation, be it transmission or distribution level, wholesale or retail markets, interoperability will become more and more important. This has been recognised some time ago for data exchanges related to TSOs, RSCs and ENTSO-E and has now also been put on top of the European agenda for data exchanges that directly concern (end)-consumers.

Demand-side flexibility and, specifically, the regulatory framework for independent aggregation are relevant topics for the INTERRFACE project. One of the core project aims is to provide new services, market rules and coordination functions for pooling and allocating distributed flexibility, stemming from distributed energy resources, demand aggregators and grid assets. INTERRFACE demonstrators aim to implement solutions for a seamless pan-European electricity market to which all market participants, incl. those that use intermediaries such as aggregators, have access to provide energy services. The findings of Section 3 inform INTERRFACE demonstrators, which aim to unlock (demand-side) flexibility via aggregation, about the implementation of an appropriate regulatory framework for independent aggregation and the relevant practical implementation challenges.

2. Data exchange and interoperability

2.1 Network, market and consumer data and data exchange in existing EU legislation

Data is becoming a key commodity in the electricity sector and data management is increasingly important for all actors involved.[8] Driven by market integration, more and more network and wholesale market data is exchanged at transmission-level among TSOs, RSCs and ENTSO-E and the overall level of harmonisation is high.[9] At distribution-level, data volumes are increasing due to the deployment of smart grids and smart metering systems. New consumer rights to download and share their own energy data with third parties increase the need to efficiently organise the exchange of and the access to energy consumer data. Currently, practices related to consumer data are widely divergent across Member States.

This part of the deliverable looks at data exchange provisions in the network codes and other relevant European legislation such as the Clean Energy Package (CEP).[10] Please note that the descriptions are not necessarily exhaustive. We focus on two issues: the level of harmonisation of data exchange and the level of access to data. In Section 2.1.1, we introduce a generic framework to discuss the level of harmonisation and describe high-level principles concerning access to data. In Sections 2.1.2 and 2.1.3, we apply the framework to respectively network and market data, and consumer data. In both sections, we also discuss the level of access to the respective data.

This part of the deliverable was published as a chapter of a Technical Report (Schittekatte et al. 2020) in July 2020, following a Florence School of Regulation online training on the EU electricity network codes and guidelines. In the context of the related online training we also organised an online expert panel in November 2019 to discuss different elements of network, market and consumer data management and data exchange.

2.1.1 Framework to discuss the issues related to data

This section is split into two parts. Subsection 2.1.1.1 discusses the aspects of data exchange that could be subject to harmonisation. Subsection 2.1.1.2 looks at the aspects of access to data that could be subject to regulatory requirements.

2.1.1.1 Aspects of data exchange potentially subject to harmonization

The electricity system can be described as a 'system of systems', that means it consists of multiple, smaller or larger systems that need to share information by means of exchanging data between their Information Technology (IT) systems. The challenge with such complex systems is that they are not built from scratch. Rather, the integration of electricity networks and markets takes place gradually

[8] Data is the '*representation of facts as text, numbers, graphics, images, sounds or videos. These facts are captured, stored and expressed as data.*' Information is '*data in context. Without context, data are meaningless; we create meaningful information by interpreting the context around the data. The context includes the business meaning of data elements and related terms; the format in which the data are presented; the timeframe represented by the data; and the relevance of the data to a given usage*' (ENTSO-E et al., 2016). Data management encompasses the processes by which data is '*sourced, validated, stored, protected and processed, and by which it can be accessed*' (CEER 2016).

[9] RSCs perform tasks related to TSO regional coordination, including coordinated security analysis, coordinated capacity calculation, improved individual/common grid model delivery, short-term adequacy and outage planning coordination. RSCs will be replaced by Regional Coordination Centres (RCCs) by 1 July 2022 as is required by the e-Regulation Art. 35(2)).

[10] In this part of the deliverable, we refer to the recasts of the e-Directive and e-Regulation adopted as part of the Clean Energy Package when we say 'e-Directive' and 'e-Regulation'. References to earlier versions are explicitly highlighted.

and new networks, systems, devices, applications or components must be integrated into the existing system. As a result, IT systems from different vendors are in place across the electricity system, often even within the same company.

The traditional way to interconnect these IT systems that often use proprietary data exchange formats is to build specialised interfaces. Uslar et al. (2005) state that *'building specialized adaptors for interconnection between the systems is the most common and time-consuming task for IT departments at energy companies.'* To address this issue and to support European smart grid deployment, the European Commission issued the Smart Grid Standardisation Mandate M/490 to the European Standardisation Organisations CEN-CENELEC-ETSI in 2011. The mandate's objective was to develop or update a set of consistent standards within a common European framework to achieve interoperability and enable or facilitate the implementation of different smart grid services and functionalities in Europe. Thereby, different digital computing and communication technologies and electrical architectures, and associated processes and services could be integrated. One result of the mandate was the Smart Grid Architecture Model (SGAM) framework that can be used to identify standardisation gaps, required use cases and security requirements.[11]

The SGAM is a three-dimensional model that is intended to present the design of smart grid use cases from an architectural, technology- and solution-neutral point of view (SGCG 2012). An important feature of the SGAM is its focus on **interoperability**, which is seen as the key enabler for smart grids. According to IEC 61850-2010, interoperability refers to the '***ability of two or more devices from the same vendor, or different vendors, to exchange information and use that information for correct co-operation***'. The SGAM framework consists of five abstract interoperability layers which represent business objectives and processes, functions, information exchange and models, communication protocols, and components as summarised in Table 2. Since its development, the SGAM framework has been used in several European and national R&D projects (see Uslar et al. (2019) for an overview).

Table 2: Mapping of aspects we discuss related to network and market, and consumer data to the five interoperability layers of the SGAM framework

SGAM Interoperability layer	**Typical aspects represented acc. to (SGCG, 2012a)**	**Aspects we discuss related to network and market data**	**Aspects we discuss related to consumer data**
Business Layer	Regulatory and economic (market) structures and policies; business objectives and processes	Relevant provisions in the Third Energy Package, the Transparency Regulation and the network codes and guidelines	Relevant provisions in the Third Energy Package, Clean Energy Package and General Data Protection Regulation
Function Layer	Functions and services including their relationships	Use cases selected for the purpose of this text related to the TYNDP, the ENTSO-E Transparency Platform and the Common Grid	Use cases and Data Management Models

[11] Please see a figure of the SGAM framework on page 30 of the report by SGCG (2012a), available at https://ec.europa.eu/energy/sites/ener/files/documents/xpert_group1_reference_architecture.pdf.

		Model for capacity calculation	
Information Layer	Information objects, canonical data models	Common Information Model and harmonised data format	Interoperability requirements and data formats
Communication Layer	Communication protocols and data exchange mechanisms	ENTSO-E Communication and Connectivity Service Platform	National practices
Component Layer	Physical distribution of all participating components in a smart grid context	Physical Communication Network	

In this chapter, the SGAM serves as a framework to discuss the level of harmonisation of data exchange processes and the related infrastructure in the European electricity sector (see Table 2). Harmonisation efforts can take place on every layer but full harmonisation is not always aimed for. Often national specifics and/or existing solutions need to be considered. Note that, for the purpose of this Deliverable, the current use case selection regarding network and market data is limited to the transmission domain.

2.1.1.2 Aspects of access to data potentially subject to regulatory requirements

With 200 million smart meters for electricity expected to be installed by 2020 (ENTSO-E, 2019a) and both transmission and distribution grids becoming more digitalised, questions on how to manage the increasing amounts of network, market and consumer data arise. Clarity is needed on who has access to which type of data and for which purpose. The Clean Energy Package requires Member States to ensure the highest level of cybersecurity and data protection as well as the impartiality of the entities processing the data.

Data access is highly regulated. While access to network and market data is mostly subject to European regulation, access to energy consumer data is regulated on a national level. For network and market data, access can be divided into restricted access, open access with exceptions and open access without exceptions. The latter relates to transparency obligations of TSOs, DSOs, production, generation or consumption units, operators of direct current links, power exchanges, and operators of balancing markets. For consumer data, access can be divided into access of the consumer to her own data and access of eligible parties to consumer data. Until recently, such data was of interest mostly for DSOs and suppliers for traditional retail services such as billing or supplier switching. With the increasing deployment of smart meters and consumer empowerment through new rights, services based on data sharing with third parties are on the rise and access to consumer data is increasingly in the focus of regulators.

Among the aspects of access to data that are potentially subject to regulatory requirements are data protection, cyber security, transparency and publication of data, and roles and responsibilities of data handling entities to ensure non-discriminatory access and to prevent distortion of competition.

2.1.2 **Applying the framework to network and market data**

This section consists of two parts. In Subsection 2.1.2.1, we look at the level of harmonisation regarding network and market data on the European level. In Subsection 2.1.2.2, we discuss the level of transparency of and access to network and market data.

2.1.2.1 Level of harmonisation

In what follows, we discuss harmonisation efforts on a layer-by-layer basis. The business layer refers to provisions in relevant legislation. The function layer covers selected use cases. On the information layer, the Common Information Model (CIM) and the harmonised data format are described. The communication layer describes the existing communication platform 'ENTSO-E communication and Connectivity Service Platform' (ECCo SP). The component layer looks at the development of a dedicated Physical Communication Network (PCN).

Business Layer: Relevant provisions in the Third Energy Package, the Transparency Regulation and the electricity network codes and guidelines

Until around one decade ago, pan-European network and electricity market data were only available to a limited audience (Egerer et al. 2014). The Third Energy Package set in motion a process towards greater transparency of network and market data, thereby increasing the need for data exchanges and common processes and technical solutions to facilitate these exchanges. Regulation (EC) No 714/2009 required ENTSO-E to adopt a non-binding Community-wide Ten-Year Network Development Plan (TYNDP) based on national investment plans and taking into account regional investment plans every two years (EC 2009b).[12] Regulation (EU) No 543/2013 (in the following 'Transparency Regulation') required ENTSO-E to create a Transparency Platform for the central collection and publication of data relating to generation, transportation and consumption of electricity for the whole ENTSO-E area (EC 2013).[13] Both projects require more than 40 TSOs across Europe to send data to a central platform. Later, the market and system operation guidelines were the starting point for additional projects that further increased the need for seamless data exchanges among TSOs, RSCs and ENTSO-E.[14]

Function Layer: Selected use cases

Three uses cases are selected by the authors for the purpose of this text to illustrate the complexities around data exchanges among TSOs, RSCs and ENTSO-E: the publication of data on the ENTSO-E Transparency Platform, the building of the Common Grid Model (CGM) for capacity calculation purposes, and the development of the Ten Year Network Development Plan (TYNDP). Depending on

[12] 'National investment plans' refers to national network plans that TSOs need to submit annually to the respective NRA, as required by Directive 2009/72/EC (EC 2009a).

[13] The ENTSO-E transparency platform is available at https://transparency.entsoe.eu/. Hirth et al. (2018) list other sources for power system data, e.g. ENTSO-E's data portal/power statistics, Eurostat, national statistical offices as well as data collected from individual TSOs' websites. Note that the Transparency Regulation (EU) No 543/2013 is binding in its entirety and directly applicable in all Member States but is not fully binding for non-EU TSO members of ENTSO-E.

[14] Projects in the area of the market codes include SDAC/SIDC, the balancing platforms, and the Single Allocation Platform (JAO). An example for a project in the area of the operation codes is Coordinated Security Analysis. Some projects also cross the two domains, such as Coordinated Capacity Calculation, the Common Grid Model, Short-Medium Term Adequacy Forecast, (regional) outage coordination, or publications to ACER.

the use case, different types of data need to be exchanged as illustrated Table 3. Note that none of the selected use cases includes the exchange of real-time data.[15]

Table 3: Selected use cases and relevant types of data

	ENTSO-E Transparency Platform	Common Grid Model for capacity calculation	TYNDP
Network data[16]	none	Structural and forecast data[17]	Structural and forecast data[174]
Market data	Forecast, scheduled and actual data	Forecast and scheduled data	Forecast data

Four types of non-real-time data can be distinguished. **Structural data** means general and permanent data of the assets, e.g. characteristics, attributes and capabilities.[18] **Scheduled data** means data on outage planning, on generation-load programs or on the exchange of electricity for a given time period. **Forecast data** refers to the best estimate of market conditions or operational conditions of the transmission system for a given timeframe. **Actual data** means ex-post data published after the operating period, e.g. data related to realised generation-load programs, cross-zonal physical flows, congestion management measures, or volumes and prices of activated balancing reserves.

ENTSO-E Transparency Platform

On its Transparency Platform, ENTSO-E publishes fundamental close-to-real-time market data on load, generation, transmission, balancing, outages and congestion management. ENTSO-E is the platform operator, while the data itself is provided by Primary Data Owners (PDO).[19] Most PDOs do not provide their data directly to ENTSO-E but through intermediaries, called Data Providers (DP). The data flows as follows: PDO to DP to ENTSO-E's TP to data users.[20]

[15] Article 42(1) of the SO GL states that real-time data exchange between TSOs of the same synchronous area shall be done using the IT tool for real-time data exchange at pan-European level as provided by ENTSO-E. This is an existing tool called 'ENTSO-E Awareness System (EAS)'. TSOs also exchange real-time data via their supervisory control and data acquisition (SCADA) systems and energy management systems (SO GL, Art. 42(2)). The component layer provides more details on the infrastructure for real-time data exchange.

[16] In this text, we understand network data as the equivalent of the data needed to create grid models.

[17] The *Common Grid Model Methodologies* refer to forecast network data as *variable* data needed to incorporate up-to-date operating assumptions. Examples are settings for various items of equipment needed to describe the forecasted behaviour of the transmission system, including variable data on grid topology, energy injections and loads, operational limits, control settings of regulating equipment, and assumptions on adjacent grids.

[18] Examples for structural data can be found in Article 48 of the SO GL or the Generation and Load Data Provision Methodologies pursuant to CACM GL and FCA GL.

[19] The Transparency Regulation defines PDOs per data category. PDOs can be TSOs (or, if applicable, transmission capacity allocators), DSOs, production, generation or consumption units, operators of direct current links, power exchanges, and operators of balancing markets.

[20] At the time of writing, more than 50 DPs (incl. all TSOs and most PXs), several thousand PDOs and around 13,000 users are registered on the platform (ENTSO-E, 2019a; Hirth et al., 2018).

Depending on the type of data and the time-frame it covers, the publication deadline for ENTSO-E varies.[21] Note that some of the intermediaries (e.g. Nord Pool) operate their own transparency data platforms to fulfil requirements under the REMIT Regulation (EC 2011), which can create overlaps with the ENTSO-E TP.[22] Other issues identified with the Transparency Platform are related to gaps in data availability, timeliness of data publication, the usability of the available data and inconsistent interpretation of data definitions by different data providers (EC 2017a; Hirth et al. 2018).[23] Art. 4(1) of the Transparency Regulation states that PDOs themselves shall ensure that the data they provide to TSOs or to DPs are complete and of the required quality. NRAs shall ensure that the PDOs, TSOs and DPs comply with their obligations under the Regulation (Art. 4(6)). Note that the liability of the PDOs, the DPs and ENTSO-E is limited to cases of gross negligence and/or wilful misconduct and in any event the parties shall not be liable to compensate the person who uses the data (Art. 18).

Common Grid Model for capacity calculation

In the following, we provide a short summary of the interplay between the Common Grid Model (CGM) and coordinated capacity calculation. The creation of a CGM is a pan-European process to be completed by all TSOs in coordination with merging agents as shown in Figure 2. The role of merging agents was allocated to Regional Security Coordinators (RSCs) (ENTSO-E, 2019e; 2019j). The CGM represents one input for coordinated capacity calculation.[24] Coordinated capacity calculation is carried out per Capacity Calculation Region (CCR) by a Coordinated Capacity Calculator and can be divided into three sequential steps for the Day-ahead (DA) and intraday (ID) timeframes pursuant to Guideline on Capacity Allocation and Congestion Management (CACM GL) (Art. 27-30): creation of a CGM out of Individual Grid Models (IGMs), regional calculation of cross-zonal capacity, and validation and delivery of cross-zonal capacity.

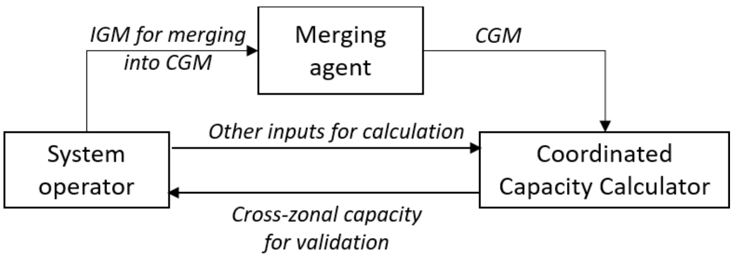


Figure 2: High-level illustration of data exchange processes for capacity calculation purposes pursuant to Art. 27-30 of the CACM GL

[21] A detailed data description is available at https://www.entsoe.eu/fileadmin/user_upload/_library/resources/Transparency/MoP%20Ref02%20-%20EMFIP-Detailed%20Data%20Descriptions%20V1R4-2014-02-24.pdf.

[22] Article 4(5) of the Transparency Platform states explicitly that data can also be published on TSOs' or other parties' websites. ACER is legally obliged to provide opinions on the ENTSO-E TP and on revisions to it. In its opinion No 02/2017, ACER (2017c) gave a recommendation on how to deal with the interactions between the different platforms. It is acknowledged that several market parties publish their inside information on the TP. According to ACER, if ENTSO-E does not want the TP to act as an inside information platform, this has to be clearly communicated to the ENTSO-E members so that market participants can use other platforms to comply with REMIT obligations.

[23] A survey commissioned by the EC (2018c) showed that 'Outages' was perceived as the data domain with the most gaps. Outages must be timely reported in the form of Urgent Market Messages (UMMs) and a lack/ inconsistency thereof is a concern for market parties who inform their trading decisions based on UMMs.

[24] In its decision on the Core CCM, ACER (2019d) states that the Common Grid Model is also considered as a capacity calculation input. However, the methodology governing its establishment is defined in the Common Grid Model Methodologies (CGMMs), thus falls outside the scope of the Capacity Calculation Methodologies (CCMs).

Important to note is that the creation of pan-European CGMs and the implementation of coordinated tasks such as capacity calculation do not necessarily mean full harmonisation in terms of their geographical scope or regarding the related processes, interfaces and tools. First, harmonisation differs depending on the geographical scope. While the CGM is created on a pan-European level, capacity calculation is currently done regionally per CCR with Capacity Calculation Methodologies (CCMs) being unharmonised across different CCRs.[25] For DA and ID timeframes, the envisaged level of geographical harmonisation is high, as the CACM GL foresees a step-wise integration of CCRs towards the target flow-based approach. For long-term capacity calculation, the geographical level of harmonisation is lower as the Forward Capacity Allocation Guideline(FCA GL) (Art. 10(2)) does not prefer one calculation approach over the other and does not foresee the merging of CCRs in the future. Nevertheless, second, the capacity calculation processes across the different timeframes are based on similar input and output data. For example, each TSO must comply with the Common Grid Model Methodologies (CGMMs) and provide harmonised IGMs to the respective merging agent for the merging process.

Given the number of TSOs, RSCs, CCRs and capacity calculation timeframes, the harmonisation of processes and interfaces provides benefits, for example facilitating the provision of large volumes of data across timeframes to ACER. As such, it makes sense that the architecture of the software tools used to exchange relevant data enables the use of a common terminology to ensure interoperability. Among the elements of such common terminology are the use of common terms and definitions and a common role model. An agreement on the terms and definitions for a specific business process such as capacity calculation allows for a common understanding among all parties involved in that business process. The use of a common role model enables the definition of data exchanges independent of specific implementations in a certain Member State or CCR. It is generally important to define data exchanges between harmonised roles to avoid lock-in effects of certain functions or responsibilities by specific parties and to facilitate comparability of different implementations, for example, between CCRs that apply different capacity calculation approaches. On the European level, the Harmonised Electricity Market Role Model has been elaborated as described in Box 1.

Box 1: The European Harmonised Electricity Market Role Model

The Harmonised Electricity Market Role Model (HEMRM) has been developed and is maintained by ebIX®, EFET and ENTSO-E to facilitate the dialogue between market participants from different countries (ENTSO-E, 2018i; ebIX, EFET, ENTSO-E, 2020; ESGTF, 2019).[26] It is not a model of the electricity market, but represents a model of the roles that are related to information exchange.

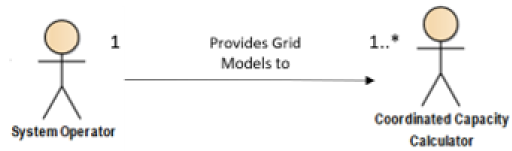
The model decomposes the electricity market into a set of commonly defined roles and domains. Having such a model is necessary because, on the one hand, a single party in the market may assume multiple roles. On the other hand, in decentralised competitive markets, every role can be taken up by a different party. To construct information exchange processes, it is necessary to clearly define the roles and to design business processes so that they satisfy the requirements of harmonised roles and not those of specific parties.

In other words, the application of the model ensures that the information exchanged between real parties corresponds to a process managed within the electricity market between distinct roles that are assumed by specific parties. For example, as described above it was decided that

[25] As can be seen from the fact that, initially, only CORE CCR and Nordic CCR intend to implement a flow-based approach, Hansa CCR aims at a hybrid approach and all other CCRs currently rely on a CNTC approach (ENTSO-E, 2019e).

[26] The latest version of the European Harmonised Electricity Market Role Model document is available at https://mwgstorage1.blob.core.windows.net/public/Ebix/Harmonised_Role_Model_2019-01.pdf.

the role of coordinated capacity calculator, to whom the common grid models ultimately need to be delivered, is allocated to the specific party RSC. In the role model, the provision of grid models is defined as the relationship (the arrow) between the harmonised roles “system operator” and “coordinated capacity calculator” as shown in Figure 3. Note that the model does not present all relationships but highlights only the major ones that justify the presence of a role or an object.



Type	Role Name	Description
Role	Coordinated Capacity Calculator	Coordinated Capacity Calculator is the entity or entities with the task of calculating transmission capacity, at regional level or above. **Source**: Commission Regulation (EU) 2015/1222 (CACM).
Role	System Operator	A party responsible for operating, ensuring the maintenance of and, if necessary, developing the system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the distribution or transmission of electricity. **Additional information**: The definition is based on DIRECTIVE 2009/72/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, Article 2 (Definitions).

Figure 3: Illustration of harmonised roles in the HEMRM relevant for delivery of grid models

Ten-Year Network Development Plan

The development of the Ten-Year Network Development Plan (TYNDP) is a process that occurs every two years and is carried out in multiple stages, including for example the collection of relevant data from TSOs by ENTSO-E, the definition of scenarios and stakeholder involvement through public consultation. Market data is essential for the set of scenarios that are the basis of the TYNDP. Each scenario represents a possible future for the European power system and contains forecast data on installed generation capacities per technology and country, consumption profiles, border reference capacities and assumptions for generator efficiencies, fuel prices and CO_2 prices. Some of the scenarios are based on collection of national data while others are the result of pan-European optimisations. Note that the TYNDP of 2018 was the first for which the ENTSOs for gas and electricity jointly developed the set of scenarios, a practice which they will continue to follow in the future.

Information Layer: Common Information Model and harmonised data format

This section is split into two parts. First, without going too far into the technical details, we focus on key points that are important to understand the differences between network and market data. Second, we discuss the application of the Common Information Model (CIM) to enable communication between the network and market domains.

The difference between network and market data

Network and market data are fundamentally different in their complexity, which results in the application of different data models and formats as shown in Table 4.

Table 4: Overview of the differences between market and network data

	Market data	**Network data**
Complexity of data structure	Low	High
Data structure	Hierarchical	Meshed
Data model	Hierarchical (XML)	Graph (RDF)
Data format applied	XML	CIMXML

Market data has a simple structure since they often refers to work processes where some data elements have more precedence over other elements. Messages used in work processes are typically document based with timeseries. Originally, such documents were paper based and structured hierarchically into sections and subsections. Today documents are typically based on Extensible Markup Language (XML) to support Electronic Data Interchange (EDI).[27] Network models, on the other hand, contain many relations between individual network objects with no obvious hierarchy or order of importance of one data element in relation to another. Network data can be described as meshed, with a complex structure.

Due to the different complexity of market and network data, different data models apply. Data models organise elements of data, define their structure and standardise the semantic relationship between concepts in the real world and concepts in computer systems. Market data is structured in an XML hierarchy. For network models, the Resource Description Framework (RDF) is used, which is based on a graph data model and designed to describe meshed data with complex structures. To be implemented in computer systems, the abstract concepts described in the data model need to be 'written down' ('serialised') by means of a data format. In other words, a data format defines how these abstract concepts in the computer system are represented using bits and bytes.[28] Note that the

[27] XML is described by Wikipedia as a markup language that defines a set of rules for encoding documents in a format that is both human- and machine-readable. ebIX (2020) also refer to Wikipedia when they further describe XML as a standard way to structure the information/datasets to exchange in messages. Electronic Data Interchange means the computer-to-computer exchange of business documents in a standard electronic format between business partners, as explained on the website of EDI, available at https://www.edibasics.com/what-is-edi/.

[28] See for example the UML contextual model for capacity used in the Transmission Capacity Allocation Business Process in Figure 1 of the Capacity Document – UML Model and Schema provided by ENTSO-E at https://docstore.entsoe.eu/Documents/EDI/Library/cim_based/schema/Capacity%20document%20model%20and%20schema%20v1-EDI.pdf.

For a simpler illustration of the relation between data model and data format, consider the following example: In the abstract data model, the entity HOTEL represents a specific hotel in Berlin, called Hotel Berlin, with the following attributes: address (street name, city, postal code), number of rooms, price, currency. In the computer system, this entity HOTEL can be represented as an XML element as follows (simplified):

```
<?xml version="1.0" encoding="UTF-8"?>
<hotels xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
  xsi:noNamespaceSchemaLocation="https://hotel.com/feed/rooms.xsd">
 <language>en</language>
 <hotel>
  <id>
    123abc
  </id>
  <name>Hotel Berlin</name>
  <address format="simple">
   <component name="addr">Florianigasse 5</component>
   <component name="city">Berlin</component>
```

data model is independent of the specific data format, e.g. RDF data can be serialised in many data formats. One of the serialisation standards used for translating RDF data into a format that can be stored and transmitted is RDF/XML. A version of RDF/XML with additional extensions and constraints is CIMXML. (Art. 114(2)) of the System Operations Guideline (SO GL) requires the use of a common European data format for TSO data exchanges, which is fulfilled by respectively using XML and CIMXML for market and network data.

Enabling communication between different domains – the Common Information Model (CIM)

For any message in any (human or computer) language to be valid, two basic building blocks are needed: syntax and semantics. While the syntax refers to the grammatical structure, the semantics refer to the meaning of the items arranged with that structure. In computer systems, the syntax of the message is defined in the data format. The use of a common data format as described above ensures *syntactic interoperability*. Syntactic interoperability refers to two or more systems communicating with each other using specified data formats (e.g. XML) and communication protocols. A higher level of interoperability is *semantic interoperability*. Semantic interoperability means that the respective systems are not only able to exchange information, but they are also able to automatically interpret the information meaningfully and accurately in order to produce useful results as defined by the end users of both systems. In simple words, a software application is needed to translate between the formats to make sure that the content of the exchange is unambiguously defined and what is sent by the sender is the same as what is understood by the receiver. Such translation is provided by a semantic data model, also called a 'canonical data model', which all involved systems must refer to.[29]

The canonical data model for TSO data exchange ('canonical CIM') is displayed in Figure 4. It is derived from the international standard of reference for data exchanges within the energy sector, namely the 'Common Information Model' (CIM), managed by the International Electrotechnical Commission (IEC).[30] To ensure the suitability of the CIM for ENTSO-E and reflect the complexities of TSO data exchanges, ENTSO-E has been working with the IEC to define specific ENTSO-E CIM standards that are of importance for the network code families for markets and operations. The canonical CIM bridges the market, network and asset domains with the aim to provide one single model and describe relations between the domains, e.g. assets performing functions in a network, or market schedules related to equipment in the network.

```
    <component name="postal_code">20367</component>
   </address>
   <rooms>123</rooms>
   <averagePrice>345</averagePrice>
   <currency>Eur</currency>
  </hotel>
</hotels>
```

[29] Imagine for example a German and an Italian speaker wanting to exchange the message '*I am going home*'. The syntax of the message is the same in both languages: '*Io vado a casa*' and '*Ich gehe nach Hause*'. To understand also the meaning, i.e. to ensure semantic interoperability, however, the two speakers need an app or a dictionary to translate and add meaning to the words exchanged.

[30] The CIM is an information model that represents all major objects in an electric utility enterprise and describes data exchange in the power industry. It consists of three families of standards covering transmission and distribution network data (IEC 61970), market data (IEC 62325) and asset and information technology/ operational technology (IT/OT) data (IEC 61968). The canonical CIM for TSO data exchange is composed of specific ENTSO-E CIM standards, namely IEC 61970-301 (CIM Base) and IEC 61970-302 (CIM Dynamics), IEC 62325-301 (CIM Extensions for Markets) and IEC 61968-11 (asset and IT/OT process related information).

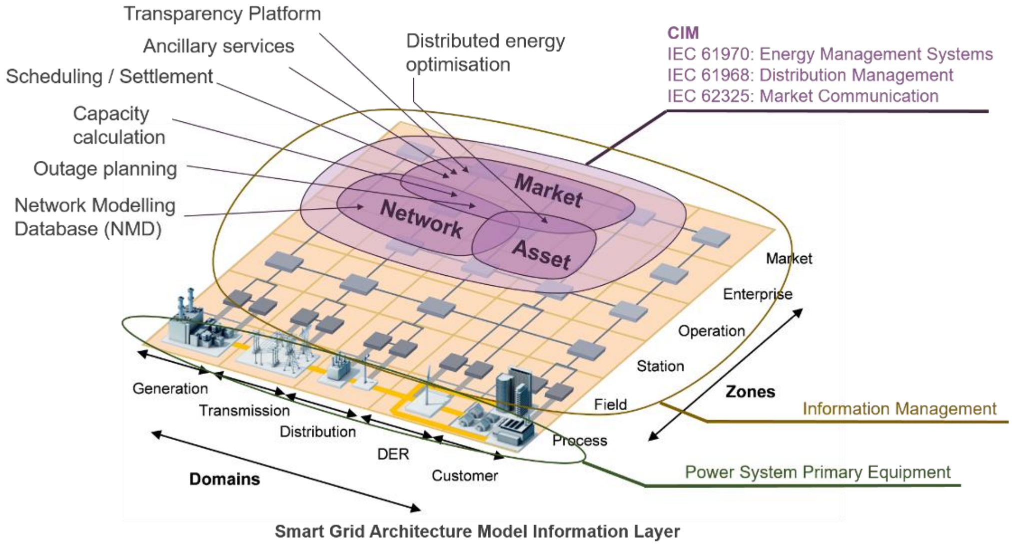


Figure 4: SGAM Information Layer displaying coverage of Common Information Model standards and related business processes (modified from** (ENTSO-E 2018b)**)

However, the canonical CIM as such is large, not practical to use and represents only an abstract model. Subsets of the model, so called 'profiles', have to be defined to specify the individual data exchanges of a certain business process. Profiles bridge the gap between the abstract canonical model and the message syntax defined by the data format by attributing meaning (i.e. semantics derived from the canonical model) to the message. Two types of CIM profiles for TSO data exchange exist: the Common Grid Model Exchange Specification (CGMES) is used to exchange network data and the European Style Market Profile (ESMP) is used to exchange market data.[31] More specifically, TSOs use CGMES for the exchange of power system models in the frame of the TYNDP and ESMPs for publishing market information on the ENTSO-E Transparency Platform. Capacity calculation relies on the use of both CGMES and ESMPs. While the CGMES is used for the creation of the CGM, ESMP profiles are used for providing other capacity calculation inputs, e.g. Critical Network Elements, Contingency Lists, Remedial Actions and Additional Constraints, Generation and Load Shift Keys. CGMES and ESMP differ regarding the level of standardisation, the development process for new profiles and the validation method applied to ensure interoperability.[32]

TSOs and RSCs are increasingly using the CIM. Currently, some RSCs (e.g. Coreso) use the CIM for capacity calculation, but use other legacy formats for other services related to system operation. It is probable that the CIM will be extended to other purposes and users. The Clean Energy Package opens possibilities for the usage of CIM, e.g. to support TSO/DSO data exchanges and to include new CIM profiles for retail markets or DSO use cases. A CIM profile for inter-TSO balancing purposes is already in use. The same profiles will be used on all four European balancing for data exchanges between market participants and TSOs as well as between TSOs and the platforms.

Communication Layer: ENTSO-E Communication and Connectivity Service Platform

In theory, TSOs have two options to send their IGMs to the merging agent responsible for merging them into the CGM: they could use the internet to send IGMs via e-mail or they could use more

[31] To be more accurate, CGMES and ESMP represent 'families' of profiles, bundling many different profiles. Please refer to https://www.entsoe.eu/digital/cim/cim-for-grid-models-exchange/ for CGMES documents and to https://www.entsoe.eu/publications/electronic-data-interchange-edi-library/ for ESMP documents.

[32] TSOs also use CGMES in the context of (regional) outage coordination and coordinated security assessment. ESMPs also cover other market processes, such as scheduling, transmission capacity allocation, and settlement and reconciliation.

sophisticated tools specifically built for the purpose of horizontal TSO data exchange. For cybersecurity reasons, the second approach is applied. ENTSO-E has been setting up a dedicated communication platform for exchanging CGM-related data that is partly used for other use cases as well.

Article 114(1) of the SO GL requires ENTSO-E to implement and operate the 'Operational Data Planning Environment' (ODPE) for the storage, exchange and management of operational planning data and relevant information among TSOs. Article 6 of the methodology for Key Organisational Requirements, Roles and Responsibilities ('KORRR methodology') states that TSOs shall use the OPDE for exchanging information among themselves and for building their IGMs (ENTSO-E 2018a). Once implemented, the OPDE will be accessible by all TSOs and RSCs and serve as an enabler for the CGM process by storing all IGMs and related information as well as the CGM for each time-frame (SO GL, Art. 114-115). ACER (2019a) reports in its first 'Monitoring report on the implementation of the CACM Regulation and the FCA Regulation' that the database for IGMs '*is implemented and most TSOs are already sending the individual grid models to ENTSO-E. Some Regional Security Coordinators (RSC) are not yet ready to use the database to create common grid models*.'

The OPDE consists of multiple parts:

- A distributed software platform called 'ENTSO-E Communication and Connectivity Service Platform' (ECCo SP) to collect and distribute the data,
- the 'Operational Planning Data Management' (OPDM) to manage and store operational planning data,
- and multiple applications providing different services to the users of the platform.

It is important to note that, strictly speaking, only the ECCo SP represents the communication layer. ECCo SP is a data exchange service bus that represents the foundation for exchanging data across business applications in the power system. It facilitates the secure communication of a wide variety of data including capacity calculation data, and market clearing data.[33]

One benefit of a widely applied communication platform is the use of common standards.[34] ECCo SP is currently mostly used across TSOs, RSCs and ENTSO-E, while some TSOs also use it to communicate with for example market participants, power exchanges or universities. ECCo SP is also used in multiple (European) research projects.[35] At a later stage, ECCo SP is expected to be opened towards other users and/or supplemented by new applications. Note in this context that it is possible to create multiple instances of ECCo SP.

ECCo SP has certain functionalities and features that are beneficial for some data exchanges but may not be needed for all types of data exchanges. ECCo SP allows the automation of processes and offers functionalities including large files transfer, publications and distributed services. It also offers message delivery features that are typically used for more critical data, such as security, reliability, transparency, portability. [36] On the one hand, ECCo SP is used by all TSO to send data to the

[33] Other data exchanged is e.g. emergency messaging services, congestion management data, flexibility plans and asset management data, and Wide Area Management System (WAMS) data.

[34] ECCo SP provides services based on the international standard Advanced Message Queuing Protocol (AMQP) and the Market Data Exchange Standard (MADES). MADES is based on IEC international standards.

[35] As for example within the INTERRFACE project.

[36] More precisely, ECCo SP is currently made of two main functional blocks, the ENTSO-E Data Exchange (EDX) software and the Energy Communication Platform (ECP) software. EDX is a distributed messaging system that allows the transfer of messages between EDX network participants. It has specific functionalities that (i) meet the need for distributed service-oriented messaging by several business processes, including OPDE, (ii) provide features beyond point-to-point messaging: large files transfer, publish-subscribe mechanism, services, message routing and much more, (iii) offer the possibility to add features without affecting the underlying communication standard, and (iv) ease

transparency platform, making use of the automated processes and functionalities of the platform. On the other hand, ECCo SP is not used for TYNDP-related data collection that takes place once every two years in one shot and does not require the message delivery capabilities of ECCo SP.

The use of ECCo SP provides benefits in terms of cybersecurity. First, messages are automatically end-to-end encrypted which means that only the two parties communicating can read what is sent. Second, in data networking, a signal is passed between communicating devices to signify receipt of the message ('acknowledgement') or reject a previously received message or indicate an error ('negative acknowledgement'). The signal informs the sender of the receiver's state so that the sender can adjust its own state accordingly. With ECCo SP, this system of acknowledgments is done automatically, thereby ensuring that no data is lost because the current state of sender and receiver as well as the location of the message are known at all times. Third, ECCo SP comes with an integrated cybersecurity certification, i.e. no additional measures need to be taken by the IT department of a platform user to ensure conformance with cybersecurity standards. [37]

Component Layer: Physical Communication Network

Data exchange, both real time and non-real time, relies on a physical infrastructure. Two different approaches exist, while a hybrid solution may also be a possibility: (i) using publicly available infrastructure, i.e. the internet, or (ii) building a dedicated infrastructure with restricted access. In Europe, data related to the TYNDP and the ENTSO-E Transparency Platform are exchanged in an encrypted manner via the internet. However, a different approach was chosen for data exchange related to the Common Grid Model (CGM). It was decided to build a new and dedicated 'Physical Communication Network (PCN)' specifically for the purpose of exchanging CGM-related data. This separate network will be classified as 'critical infrastructure'[38] and has the main objective to maintain operation and enable exchange of relevant data also in cases when the public infrastructure fails (e.g. hacker attack). Note the difference between non-real time and real time data exchange. Since 1999, a network for real time data exchange among TSOs has been in place. This 'Electronic Highway' is also separated from the internet and was set up to directly connect the European TSOs. In 2017, the decision was taken to merge the Electronic Highway with the PCN. This will create a single physical infrastructure supporting multiple real time and non-real time services.

The construction of the PCN is costly and connecting TSOs to the network is a gradual process.[39] Every extension of the network to include additional services (e.g. balancing) or users must be well thought-through and the allocation of costs needs to be agreed on and justifiable by the concerned TSOs. Note firstly, that there is no need to base all existing TSO data exchanges on the PCN and that it makes sense to use multiple communication channels addressing different data exchange needs. For example, TYNDP data can be exchanged simply over the internet and data for the transparency

the business application integration through advanced routing. ECP provides message delivery capabilities with the following features: security, reliability, integration, compliance with standards, transparency, and portability.

[37] For more detailed information about the cybersecurity aspects of ECCo SP, please see Bartol et al. (2019).

[38] Critical infrastructure as defined in Council Directive 2008/114/EC means "an asset, system or part thereof located in Member States which is essential for the maintenance of vital societal functions, health, safety, security, economic or social well-being of people, and the disruption or destruction of which would have a significant impact in a Member State as a result of the failure to maintain those functions" (Council, 2008).

[39] At the time of writing, the networks of the Austrian (APG), Swiss (Swissgrid) and one German TSO (Amprion) have been physically connected to the PCN. Other TSOs' networks are currently connected via the internet (IE, GB and the rest of the CE synchronous area, except Albania) or a routed private network (Nordics). The connection of all TSOs to the PCN is expected for 2021 (ENTSO-E, 2019a).

platform can be exchanged over the internet using the security features of ECCo SP.[40] Note secondly, that also for data exchanged via the PCN, different specifications of communication channels exist that are used for different purposes. For example, balancing requires real time communication, and the exchange of intraday IGMs requires a fast connection, while neither is necessary for year-ahead IGMs.

2.1.2.2 Level of access

This subsection is divided into three parts: first, restricted access to CGM-related data; second, open access with exceptions to TYNDP data; third, open access without exceptions to market data provided on the ENTSO-E Transparency Platform.

Restricted access to Common Grid Model-related data

The Operational Data Planning Environment (ODPE) shall be used to store all IGMs and related relevant information for all the relevant timeframes set out in the CACM GL, FCA GL and SO GL (SO GL, Art. 115(1)), as was described on the communication layer. After merging, the CGM established for each of the timeframes shall also be made available on the OPDE (SO GL, Art. 115(3)). For the DA and ID time-frame, the OPDE shall also store scheduled exchanges at the relevant time instances or scheduling area or per scheduling area border, and a list of prepared and agreed remedial actions identified to cope with constraints having cross-border relevance (SO GL, Art. 115(5)). Article 114 of the SO GL states clearly that all TSOs and RSCs shall have access to all information contained on the OPDE.

Open access with exceptions to TYNDP data

To allow public access to fundamental data on the EU power system, ENTSO-E is making TYNDP data publicly available. Slight differences exist between market and network data. Most market data used for the TYNDP scenarios is publicly available on ENTSO-E's website. Due to confidentiality reasons with the data provider, exceptions exist for efficiency assumptions per generator, operational restrictions and maintenance profiles, smaller market node data, and climatological data for hydro, wind and solar. Grid datasets are available to institutions either as standard material upon simple request; or for more advanced data, upon request, with a specific description and signature of a Non-Disclosure-Agreement. Exceptions exist where the data falls under national confidentiality laws or where the access is contractually limited to ENTSO-E. Such exceptions are regularly reviewed (ENTSO-E 2018c).

Open access without exceptions via the ENTSO-E Transparency Platform

The main gateway to access ENTSO-E's data is the Transparency Platform (TP) that serves to facilitate the market, reduce insider trading and enable a level-playing field between small and large actors (Hirth et al. 2018). As mentioned in the previous subsection, the TP provides free access to pan-European close-to-real-time electricity market data across six main categories: Load, Generation, Transmission, Balancing, Outages and Congestion Management as required by the Transparency Regulation 543/2013. Requirements to publish data under the Electricity Balancing Guideline (EB GL) and SO GL will also be fulfilled via the ENTSO-E Transparency Platform. The EB GL (Art. 12) states that '*no later than two years after entry into force of this Regulation, each TSO shall publish the information pursuant to paragraph [12(3)] in a commonly agreed harmonised format at least through the information transparency platform.*' As soon as it is available, each TSO shall publish information related to the current system balance, balancing energy bids (incl. aggregated information on balancing energy bids), procured balancing capacity, initial terms and conditions, and

[40] The usage of ECCo SP is not a function of the physical infrastructure in use. ECCo SP can be applied to a separate physical network (as e.g. in the case of CGM-related data exchange) but it can also be applied to the internet (as e.g. in the case of data related to the Transparency Platform) or a routed private network.

allocation and use of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves. Further publication obligations include approved methodologies for the allocation of cross-zonal capacity for balancing, a description of any algorithm developed and amendments to it and a common annual report on the integration of balancing markets. The SO GL (Art. 183-190) requires TSOs to publish information related to frequency, reserves and operational agreements '*at a time and in a format that does not create an actual or potential competitive advantage or disadvantage to any individual party or category of party and taking due account of sensitive commercial information*' (Art. 183(1)).

Currently, the information available on the transparency platform covers only the requirements in the legislation, yet stakeholders have raised an interest in additional data that could be made available (EC 2017a). According to ENTSO-E, the TP is envisioned to move from a regulatory platform to a market-serving tool in the future, possibly extended by data provided by the DSOs.[41] Box 2 shows an example of how the transparency platform is already in use beyond the legal requirements.

Box 2: Use of transparency information beyond the Regulation – the example of 'Tomorrow'

After its implementation in 2015, the ENTSO-E Transparency Platform was mostly used by market parties and utilities for wholesale market transparency and real time data of large units. Recently, there have been more and more initiatives to develop plug-in tools based on the available data, which goes beyond the purpose originally foreseen in the Transparency Regulation. The initiators mainly use the data to provide data services without owning or operating any assets.

One of the Data Service Providers, as mentioned in the Transparency Regulation, is the tech start-up *Tomorrow.* In 2016, Tomorrow created the *electricityMap*, an app showcasing in real-time the origin of the consumed electricity and how much carbon was emitted in the process of generating it (Figure 5). To facilitate "*a world in which every connected device uses its flexibility to consume electricity at times when the electricity is greenest*" (Corrradi 2019), the *electricityMap API* was developed. It contains an estimation of the marginal CO2 intensity of the grid in the next 24 hours. A signal based on the API can for example be used to optimise charging and discharging times for storage or charging for electric vehicles.[42]

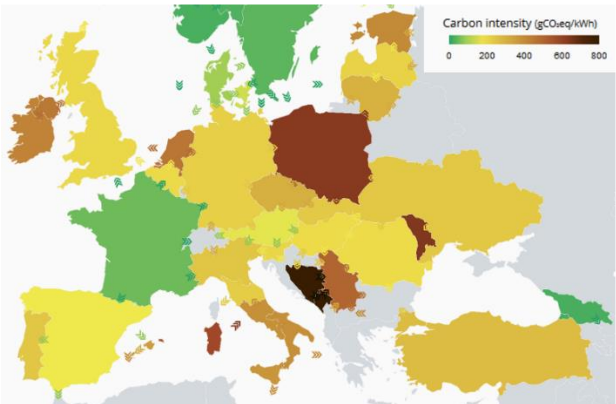


Figure 5: Carbon intensity [gCO_2eq/kWh] of electricity consumption in Europe, *(source: https://www.electricitymap.org, screenshot taken on 19/5/2020 at 11h54 CEST)*

[41] As expressed in a webinar (https://www.entsoe.eu/events/2019/02/05/powerfacts-europe-2019-webinar/).

[42] See the *Parker Project* at http://parker-project.com/. See also https://www.tmrow.com/.

2.1.3 Applying the framework to consumer data

This section is divided into two parts. In subsection 2.1.3.1, we assess the level of harmonisation regarding consumer data on the European level. On some layers, we include national best practices. In subsection 2.1.3.2, we describe the level of access to consumer data.

2.1.3.1 Level of harmonisation

In what follows, we discuss harmonisation efforts on a layer-by-layer basis. The business layer refers to provisions in relevant legislation. The function layer describes use cases and gives an overview of different Data Management Models (DMMs). The information layer covers European requirements for interoperability and national data formats. The communication and component layers are combined and describe national practices regarding communication software and hardware.

Business Layer: Relevant provisions in the Third Energy Package, Clean Energy Package and General Data Protection Regulation

Consumers have been given the right to access and share their energy data by recent EU legislation. Measures for consumer protection, provisions for interoperability of smart metering systems implemented within a Member States territory and requirements for data management were already included in the Third Energy Package (EC, 2009b).[43] These provisions were reiterated and extended in the Clean Energy Package. To foster participation of active customers in all electricity markets and enhance retail competition, the e-Directive (EU) 2019/944 together with Regulation (EU) 2016/679 (EC 2016b), also known as the 'General Data Protection Regulation' (GDPR), gives consumers the right to share their data with third parties. As specified in Art. 23(1) of the e-Directive, this covers **metering and consumption data as well as data required for customer switching, demand response and other services**. Data access and exchange must be efficiently organised, the purpose of the data collection, use and processing must be clear to the consumer and data sharing processes must be secure and are subject to the consumer's consent.

Function Layer: Use cases and Data Management Models

Article 23 of the e-Directive states that '*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*.' In the following, we first describe typical use cases for consumer data. We then describe different approaches to organising data exchange, namely centralised and decentralised.

Use cases

Use of consumer data can be generally divided into two main categories: regulated obligations and commercial services (Eurelectric 2016). Use cases related to the first category are connected to the entitlement of any customer to be connected to the grid, be supplied and billed and be provided with a high level of security of supply. Traditional retail processes (e.g. billing, change of supplier, moving, settlement, cancellation of a contract) have been implemented in most MS for many years (ESGTF 2019). To fulfil their obligations, DSOs and some other players (e.g. suppliers) need access to basic metering and network data with the right granularity for the respective process while respecting data security and privacy. New use cases are emerging in line with the new rights of consumers to download and share their own data. Commercial services are dependent on the consumers' consent to give access to their data to third parties. Examples of related use cases are 'download my data', 'share my data', 'revoke consent' and 'terminate service'. Future use cases are hard to determine but

[43] Annex I of Directive 2009/72/EC states that consumers shall '*have at their disposal their consumption data, and shall be able to, by explicit agreement and free of charge, give any registered supply undertaking access to its metering data. The party responsible for data management shall be obliged to give those data to the undertaking. Member States shall define a format for the data and a procedure for suppliers and consumers to have access to the data. No additional costs shall be charged to the consumer for that service*.'

are likely to emerge in the areas of demand response, home automation, generation/demand analysis and forecasting, offering and settlement of flexibility/balancing services, monitoring and transparency (ESGTF 2019; THEMA 2017).

Note that the line between regulated obligations and commercial services is not always that clear-cut. Until recently, data processing was considered a DSO task as few to no other players were interested in consumer data. This situation is changing, however, and who should be responsible for data management is subject to ongoing debate. Delegating data management to DSOs results in a trade-off between competition and coordination, which is discussed in more depth in Buchmann (2017). DSOs have a monopoly position and access to vast amounts of data, which means they could put together unique sets of detailed information about network users and grid characteristics, both at individual or aggregated level (CEER, 2019). As DSOs are increasingly adopting the role of a neutral market facilitator, it is important to separate between activities of providing data to the market and providing competitive data analysis services. The Clean Energy Package resolved the issue in Art. 23 of the e-Directive by stating that the relevant authority at MS level '*shall ensure that any charges imposed by regulated entities that provide data services are reasonable and duly justified*.' Thus, data services can be provided by DSOs subject to the activity being under close regulatory supervision.

Data Management Models

CEER (2016) states that the management and exchange of consumer and metering data is essential for well-functioning retail markets. Currently, Data Management Models (DMMs) vary greatly across Member States.[44] They typically consist of a set of different roles, responsibilities, legal frameworks, technical standards as well as informal rules. DMMs can be categorised according to numerous different dimensions, e.g. level of centralisation, ownership and operation, organisation, scope or set of metering points, data types, functionalities, rights of customers, access of third parties, obligations and rights of data handling entities, future development of the model (for example whether a Member State decides to remain with a decentralised model or move towards a more central model) (THEMA 2017). A fundamental distinction can be made between centralised and decentralised models as shown in Figure 6. The centralised models can either be a fully centralised model (*data hub*) or a partially centralised model (*communication hub*). Depending on the national context, the responsible party for the hub can be a DSO, the TSO or a third party (see e.g. Meeus and Hadush (2016)).

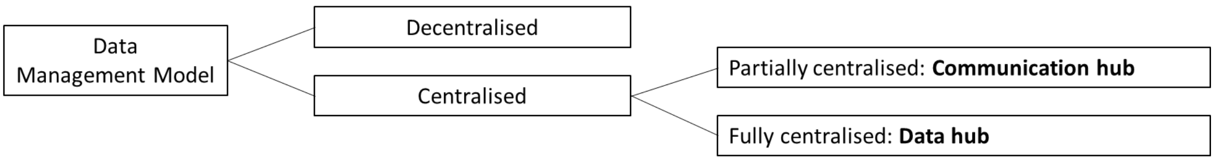


Figure 6: Overview of types of data management models

CEER (2016) describes the various types of DMMs as follows:

- In a **decentralised model**, the key aspects of data management are decentralised and within the DSO's responsibility. The means of exchanging data among market parties and the DSO is often a rather simple format, sometimes standardised yet often non-standardised (even PDF) format. Customers must specifically contact the DSO for access to data.

[44] A DMM refers to '*the framework of roles and responsibilities assigned to any party within the electricity system and market and the subsequent duties related to data collection, processing, delivery, exchanges, publishing and access*' (ENTSO-E et al. 2016). Please note the difference between data management models and data models described on the information layer.

- In a **partially centralised model**, one or few key aspects of data management are centralised, typically distribution and access to data. This model enables centralised access (via the *communication hub*) to data stored in several decentralised databases.
- A **fully centralised model** comprises the centralisation of all key aspects related to data exchange. It typically represents a one stop shop for data, where DSOs, market actors and all consumers have only one actor, the *data hub*, which they relate to. Tractebel (2018) further differentiates between centralized systems based on a central data hub and *de facto* centralized systems, where one main DSO is covering most of the market.

The choice between centralised and decentralised models seems to be mostly driven by the legacy system rather than stemming from economic considerations.[45] Traditionally, consumer data has been exchanged bilaterally between the metering operator (in most MS the DSO) and market participants, based on defined standards for common retail processes.[46] Some countries have transitioned from a decentral to a more centralised approach like Great Britain while other Member States keep their decentralised models like Germany or Austria.

In its Impact Assessment for the Market Design Initiative, the EC (2016b) identified differences in data management as possible market entry barriers for new actors. The EC 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.

TSOs and DSOs were of the opinion that no one-size-fits-all data management model is applicable in all European countries (ENTSO-E et al. 2016). National requirements shall be respected while, at the same time, common principles must be set on a European level to provide for a common framework to the different DMMs in Europe. Such common criteria and requirements shall, for example, guarantee privacy and security of data, facilitate competition, markets and innovation, guarantee neutral and non-discriminatory access to data, ensure transparency of data exchange, improve overall transparency in the power sector, consider cost-efficiency and simplicity of design decisions, business models and processes, and aim for harmonisation of standards at least on a national level and, where applicable and efficient, on a European level (ENTSO-E et al. 2016; THEMA 2017).

Among the interoperability challenges for consumer data are national differences in traditional retail process and the handling and definition of specific processes for exceptions. Traditional retail processes like switching or billing vary regarding the number of interactions needed between market participants to complete the process. Exceptions can be due to countries taking account of regional aspects related to public service obligations or taxes and levies. A high degree of harmonisation across Member States is considered unlikely in the short-term as individual countries have invested much time, effort and cost into specifying processes and developing standardised procedures and formats on a national level. The implementation of emerging services could face fewer obstacles. However, differences between Member States as regards the speed of smart meter deployment, the history and granularity of consumption data, and smart meter functionalities remain. These differences can pose challenges to the interoperability of services based on data sharing.

Box provides information on the role of ebIX® in the harmonization of downstream market processes in the EU.

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[45] This is a statement from Tractebel (2018) based on a survey asking whether the choice of the model has been the result of a CBA. Regarding advantages and disadvantages of centralised and decentralised models, please see CEER (2016, 2012). The reports summarise information provided by NRAs based on their experience with their current DMMs and their expectations towards future development of their DMMs.

[46] An overview of the relevant responsible parties across Member States is provided at https://ses.jrc.ec.europa.eu/smart-metering-deployment-european-union.

Box 3: ebIX® role and deliverables in harmonization of downstream market processes in the EU

ebIX® provides standardised and harmonised processes for the liberalized downstream electricity and gas markets with the focus on information exchange, following EU rules and allowing national customization. More precisely, ebIX® offers implementable process models, including the definition of information exchanged, based on best practices and lessons learned in member countries, using open international standards, and using "business language" to make it as understandable as possible for the businesspeople. In addition, ebIX® offers a forum for knowledge sharing between member countries.[47]

The ebIX® models are based on the Harmonised Role Model (see Section 2.1.2). ebIX® offers harmonised business requirement specifications (BRS) for all core downstream business processes in the European electricity and gas sectors, based on experience and best practices. These include administration of consent, change of supplier, customer move, end of supply, alignment of accounting point characteristics, alignment of characteristics of a customer, alignment of metering configuration characteristics, alignment of area characteristics, manage accounting points, upfront request for metering point characteristics, change of balance responsible party and shipper, change of metered data responsible, end of metered data responsible, combined grid and supply billing, measure collected data, measure/determine meter read, measure for imbalance settlement, measure for labeling, measure for reconciliation, measure for billing, overview of energy flexibility services, and others.

The ebIX® UML model for the European energy market with related BRS and Business Information Models (BIM) may be a framework to be used when implementing data exchange in a national energy market. Some ebIX® member countries have implemented different versions of the ebIX® model, normally with extension of national specialities. In other ebIX® member countries selected eBIX® BRS were taken as reference models for national implementation.

The ebIX models are presently the only known available process model for the downstream energy market and are considered important in the process of achieving interoperability. They can be used as a basis for implementation of some of the needed domain reference models on the function layer (ebIX BRS) as well as on information layer (ebIX BIM) while allowing for national or regional specifics and customization.

Information Layer: Interoperability requirements and data formats

Integration of national retail markets is seen as more difficult than wholesale market integration due to the existence of different processes and data exchange procedures across Member States (Eurelectric 2016). While there is widespread agreement that the best solution for managing consumer data must be assessed for each national context rather than on European level, it is acknowledged that a lack of standardisation and interoperability can pose barriers to retail competition (ENTSO-E et al. 2016; Eurelectric 2016). For example, retailers wanting to expand their business to other MS currently often have to set up parallel IT infrastructures to accommodate the different systems and processes in place across countries.

The original proposal for a recast of the e-Directive (EC 2017b) foresaw the implementation of a harmonised European data format for consumer data. More precisely, article 24 of the original

[47] Note that ebIX® participates in several relevant working groups at the European level and has several liaison agreements, for example with IEC. Under the cooperation between ebIX® and IEC/TC57/WG16, ebIX® has drafted an IEC Technical Report with the results of the mapping of ebIX® Business requirements to IEC basic CIM.

proposal stated that '*Member States shall define a common data format and a transparent procedure for eligible parties to have access to the [metering and consumption data as well as data required for consumer switching] in order to promote competition in the retail market and avoid excessive administrative costs for the eligible parties.'* And further that '*The Commission, by means of implementing acts [...] shall determine a common European data format and non-discriminatory and transparent procedures for accessing the data that will replace national data format and procedure adopted by Member States [...]. Member States shall ensure that market participants apply a common European data format.*'

The European Smart Grids Task Force Expert Group 1, in their aim to advise on the preparatory work for implementing acts pursuant to article 24, published the report 'My energy data' on standards and interoperability of consumer data (ESGTF 2016). The report states that a common data format and model would allow unified hardware procurement, better alignment and co-operation with international partners and on international markets, and facilitate service interoperability.[48] However, most countries have not assessed the potential for harmonisation of data standards on a regional or European level (CEER, 2016). Rather, most countries focus mainly on some form of national standardisation of data formats and/or exchange.

In the final version of the recast of the e-Directive, the harmonised European data format was removed and replaced by interoperability requirements. '*In order to promote competition on the retail market and to avoid administrative costs for the eligible parties*', Article 24 of the e-Directive states that '*Member states shall facilitate the full interoperability of energy services within the Union.*' And further, that the '*Commission shall adopt, by means of implementing acts, interoperability requirements and non-discriminatory and transparent procedures for access to data.'* ENTSO-E shall contribute to their establishment, as required by the e-Regulation (Art. 30). Member States shall ensure that electricity undertakings apply the interoperability requirements and procedures for access, which shall both be based on existing national practices.[49]

The European Smart Grids Task Force Expert Group 1, aware of the amendments made to Article 24, continued its task and published a follow-up report on interoperability of data access and exchange (ESGTF 2019).[50] The aim of the second report was to map national practices in the EU for data access and exchange, including also for the new use cases mentioned on the function layer, and to reflect on available options or potential steps for making them interoperable. Existing national practices vary widely across Member States, with one exception being the Nordic countries as discussed in

Box . Most countries use specific data formats (often txt-, csv- or xml-based) and models (see also ESGTF (2016) and Tractebel (2018)). Regarding the usage of standards, different levels of maturity exist across Member States. Some use merely syntactic norms (e.g. EDIFACT) while others use (international) semantic standards (e.g. Common Information Model (CIM)) or consider moving to one. The ESGTF (2019) states that, on the way towards interoperability, '*emphasis should be put on convergence over time, as opposed to short-term obligation to harmonise, while respecting and building upon established national structures and practices.*' Convergence of two or more different systems is understood as the gradual process of changing and developing similar characteristics in order to become interoperable.

To achieve this, a framework of different 'reference models' is considered important. This would include a reference core process model, representing harmonised processes for information exchange within the energy sector while allowing for national or regional specifics and customisation. Such core process model would also include the usage of a semantic information

[48] Service interoperability means that a service developed in one national market could easily be sold in another.

[49] The topic of interoperability following Art. 24 of the e-Directive is further discussed in Reif and Meeus (2020).

[50] A supporting document to the final report with technical information is available at https://ec.europa.eu/energy/sites/ener/files/documents/eg1_supporting_material_interop_data.pdf.

model along with a harmonised role model. Note that beyond the ones mentioned in this chapter, other data and information models, role models and standards exist and are being used across MS. In the words of the report, '*whatever model is to be proposed at the end, it has to be inclusive, technology-neutral, cost-effective and should not favour a specific ICT solution*' (ESGTF 2019).

Box 4: Regional retail market harmonisation – the example of the Nordics

Since 2005, the ministries and regulators of DK, FI, NO and SE (here the 'Nordics') have been working towards harmonising their electricity retail markets. The main aim is to reduce market entry barriers for retailers who want to extend their business to other Nordic countries and to improve user experience by implementing a supplier-centric model (NordREG 2014).[51] Note that here the aim is not to implement a single retail market. Four separate retail markets with many similarities and some differences exist and will continue to exist.

To facilitate harmonisation, all Nordic countries are moving towards the implementation of data hubs for metering data and market processes. At the time of writing, only the Danish (*DataHub*) and the Norwegian (*Elhub*) hub are implemented. Regarding market processes, NordREG (2014) identified four focus areas that should be prioritised: combined billing, supplier switching and customer moving, information exchange and customer interface. The processes of switching, moving and billing have been largely harmonised at Nordic level and are awaited to be implemented on a national level. Most of the remaining known market barriers are expected to be addressed with the completion of the smart meter roll-out and the implementation of data hubs in all countries. However, some differences were identified by TemaNord (2017) where harmonisation is more difficult if not unlikely as they are mainly related to local regulations either beyond data exchange or even beyond the energy sector, including licencing, privacy and security provisions beyond the GDRP, and taxation.

It is important to note that while the harmonisation of business processes is largely completed in the Nordics, harmonisation gaps exist on a technical level that lead to barriers due to IT system costs. Currently, a supplier needs to comply with one interface for each hub, which constitutes a market barrier due to the need and costs to operate four IT subsystems in parallel. Data models are not harmonised, different data formats exists and the number of interfaces is not optimally reduced (TemaNord 2017). Future harmonisation efforts need to address the lack of a common data model and the number of interfaces needed to operate in the different markets. Differences in data formats are not considered a main barrier as only Denmark differs slightly (TemaNord, 2017).

Communication and Component Layer: National practices

As outlined on the component layer above, the alternative to building a dedicated communication network is the use of public infrastructure. For the exchange of consumer data, the internet is widely used across Europe. In some countries, e-mail communication is still among the prevailing means to exchange consumer data and data related to market processes. In other countries, comprehensive communication environments have been built to deal with consumer data exchange related to, *inter alia*, customer consent management, community generation units, electronic billing, consumption data, and switching. One example is Austria, were the so-called '*Energiewirtschaftlicher Datenaustausch (EDA)*' was introduced in 2012 and XML formats, business processes and the

[51] The supplier-centric approach proposed by NordREG is explained by TemaNord (2017): '*suppliers would pass on network costs to customers in the form of combined bills, be responsible for ensuring payments of network costs, and handle the processes of switching and moving. National information exchanges (datahubs) would serve as the backbone of the supplier-centric model and facilitate harmonisation of the Nordic retail markets*.'

communication protocol were standardised.[52] While EDA provides an interoperable solution for a decentralised data management model, other countries have implemented centralised models and are exploring cross-border applications as shown in Box 5. Note that smart metering systems and their deployment are described in more detail in subsection 2.1.3.2.

Box 5: Example of national data exchange platform – Estonia

The Estonian Data Exchange Platform *Estfeed* is considered state-of-the-art regarding data exchange in the European context. Estfeed is a distributed system that is owned and operated by the Estonian TSO Elering. The platform consists of legal, software and hardware solutions to manage the exchange of metering data among the market participants, support the electricity supplier change process in the open market and, subject to the consumer's consent, enable access of third party software applications to metering data (EC 2018a).

Estfeed is based on X-Road, a data exchange layer that was first introduced in 2001 and constitutes the backbone of e-Estonia.[53] Data is stored in specific data hubs (e.g. Electricity Data Hub, Gas Data Hub, Central Commercial Register, Electricity price (Nord Pool), weather forecast (Foreca)). In accordance with the GDPR, the consumer agrees to share meter data with a specific energy service company. Messages on X-Road are transmitted in XML format via the public internet using the standardised HTTP 1.1. protocol.[54]

At the European level, Estfeed provides the opportunity to combine retail markets and facilitate cross-border energy services. Data hubs exist in several countries but until now there has not been a way to easily and securely exchange data and access different data hubs. In this context, Estfeed is also part of European research projects that explore the possibilities of widening the concept of the platform to cross-border electricity data exchange.[55]

2.1.3.2 Level of access

This subsection is divided into two parts: first, access of consumers to their own data; second, access of eligible parties to consumer data. Box 6 covers cyber security and data protection.

Access of consumers to their own data

Traditionally, consumers can consult their historical consumption data in different, country-dependent time granularities via their electricity bill and/or via request to the DSO or the supplier. The roll-out of smart metering systems opens possibilities for easier access to data. The Third Energy Package asked Member States to carry out a Cost-Benefit Analysis (CBA) for smart metering systems. In the case of a positive assessment, at least 80 % of consumers should be equipped with smart metering systems by 2020. These provisions were reiterated in the e-Directive of the Clean Energy Package. As stated in Annex II of the e-Directive "*where deployment of smart metering systems is assessed positively, at least 80 % of final customers shall be equipped with smart meters either within seven years of the date of the positive assessment or by 2024 for those Member States that have initiated the systematic deployment of smart metering systems before 4 July 2019*." Where the outcome of the CBA is negative, Member States shall ensure that the assessment is revised at least every four years,

[52] EDA is based on a communication software that uses the protocol ebXML. It has helped to replace e-mail as the main means of communication, standardise data exchange processes, and reduce integration efforts. EDA is also accessible to international market participants active in Austria. More information (in German language) is provided at https://www.ebutilities.at/home.html.

[53] X-Road has been used in the Estonian public and private sector for over two decades. Since 2013, a cooperation between Estonia and Finland aims at jointly developing the X-Road technology further (https://e-estonia.com/).

[54] See https://elering.ee/sites/default/files/attachments/estfeed_protocol_1.15_Y-1029-1.pdf.

[55] See e.g. EU Sys-Flex, available at http://eu-sysflex.com/.

or more frequently, in response to significant changes in the underlying assumptions and to technological and market developments (Art. 19(5)). Figure 7 shows that most Member States have conducted a CBA as of July 2018 and that the result was mostly positive.

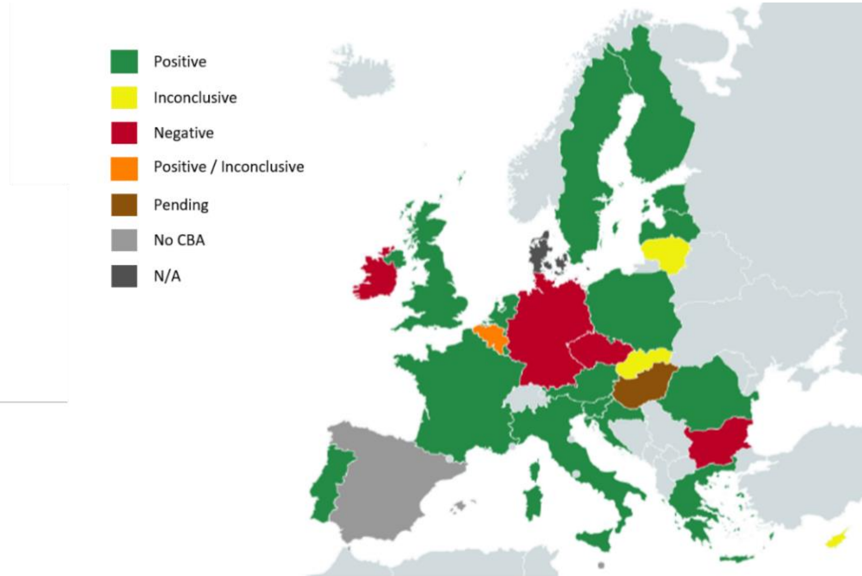


Figure 7: Revised CBA results electricity smart meters considering a large-scale roll-out to at least 80 % by 2020 (as of July 2018), figure modified from Tractebel (2019)

Article 20 of the e-Directive states that in case of a positive CBA for smart meters or where they are systematically deployed:

- Smart metering systems shall accurately measure actual electricity consumption and shall be capable of providing to the 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 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.
- If the 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 [on interoperability requirements and procedures for access to data] 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 this purpose, 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 the GDPR. Article 20 of the GDRP states that consumers have the "*right to receive the personal data concerning him or her, which he or she has provided to a controller, in a structured, commonly used and machine-readable format and have the right to transmit those data to another controller without hindrance from the controller to which the personal data have been provided, where the processing is based on consent or on a contract and the processing is carried out by automated means.*"
- Smart metering systems shall enable final customers to be metered and settled at the same time resolution as the imbalance settlement period in the national market.

Article 20 also includes requirements related to (cyber)security, data protection, and consumer information.

A difference seems to exist between *de jure* access to data that the consumer is entitled to by relevant legislation and *de facto* access as a result of slow progress in smart meter deployment. In its recent report on smart metering deployment in the EU-28, Tractebel (2019) found diverse deployment and penetration rates across Member States. According to their report, seven Member States have reached 80 % (DK) or finished their large-scale electricity smart metering roll-out (EE, FI, IT, MT, ES, SE), with some of these already proceeding with a second-generation smart meter roll-out or at least planning for it. However, only few of the other Member States that had committed to an 80 % roll-out of smart metering systems by 2020 are still on track and some of them are now postponing this target to be reached only in 2030. The report states that 34 % of all electricity metering points in the EU-28 were equipped with a smart meter as of 2018. Based on the observed rate of deployment of electricity smart meters in 2017, the authors estimate a penetration rate of only 43 % in 2020 and of 92 % in 2030.

In its Commission Recommendation 2012/148/EU, the EC (2012) defines ten minimum functionalities for smart metering systems, mainly applicable of electricity. The three most important functionalities of smart metering systems related to the engagement of consumers are those to provide readings directly to the consumer and/or an 3rd party, to upgrade readings frequently enough to use energy savings schemes and to support advanced tariff schemes. The report by Tractebel (2019) finds that most Member States envisage to make all ten smart meter functionalities available to their electricity consumers, many of them activated by default and free of charge for the consumer. The frequency at which consumption data is (foreseen to be) updated and provided to the customers varies across Member States between near real-time to hourly or even daily.

Access of eligible parties to the data of the final customer data

Article 23 of the e-Directive regulates the management of data, including metering and consumption data as well as data required for customer switching, demand response and other services. It states that Member States, or, where so provided, the designated competent authority shall specify the rules on the access to data of the final customers by eligible parties.[56] Article 23 states further that *'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 […]. 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.'* Member States 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 the e-Directive. Final customers shall not be charged additional costs for access to their data or for a request to make their data available to eligible parties. Member States are responsible to set the relevant charges for access to data by eligible parties. The regulatory authority shall ensure 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 (e-Directive, Art. 59(t)).

Article 34 of the e-Directive regulates in more detail the tasks of DSOs in data management. In MSs where smart metering systems have been deployed and where DSOs are involved in data management, compliance programmes must be established by DSOs that include specific measures in order to exclude discriminatory access to data from eligible parties. Furthermore, where DSOs are not subject to the unbundling provisions for DSOs set out in Article 35 of the e-Directive, MS shall

[56] In the original EC proposal, eligible parties were specified as including at least customers, suppliers, TSOs and DSOs, aggregators, energy service companies, and other parties which provide energy or other services to customers. This was removed in the final version of the CEP.

'*take all necessary measures to ensure that vertically integrated undertakings do not have privileged access to data for the conduct of their supply activities*.'

Currently, the smart metering-roll-out is DSO-led in almost all Member States except for the UK (supplier-led) and Germany (by default DSO-led unless the DSO refuses to perform the mandatory roll-out or a customer chooses a 3rd party meter operator for smart meters) (Tractebel, 2019). DSOs have vast amounts of data at their disposal that can be roughly divided into three categories according to E.DSO (2018). First, metering data, typically collected at the customer's premises, including consumption and production data. Second, network data, which includes information on the grid, its configuration and measurements, and can either be real-time, planned or historic. Third, market data, which refers to all types of exogenous data, such as market results or information on installations at customer premises necessary to offer services related to those assets.

In terms of data ownership, there is a divide between network data which belongs to the DSO and consumption data which belongs to the consumer. However, DSOs must always be able to use consumption data to perform their core tasks, e.g. for operational and planning purposes (CEER 2019). When it comes to the DSOs' role with respect to individual data and the separation of providing data to the market as a neutral market facilitator and providing competitive data analysis, the distinction may not always be so clear, and the details also depend on national legislation as is described by CEER (2019). On the on hand, the provision of raw meter data to energy companies like suppliers is a core task of DSOs where they are responsible for metering. On the other hand, and where foreseen by national legislation, some DSOs have chosen to or were mandated to go beyond the provision of raw meter data. Instead, they have added an additional service or analysis to the data they provide, which under the legislative regimes of other countries could be marked as an additional service to customers.

CEER (2019) concludes by saying that boundaries between the DSOs' core activities and the provision of other services must be clearly drawn. At the core of the DSOs' activities are the design, maintenance, development and operation of the distribution system, which includes the provision of relevant network information to third parties to enable them to provide their services. Connection and metering activities can be also considered as core activities. Where activities are open to competition, including data analysis services and providing enriched data to third parties, the DSO should not be allowed to be active in that area. Exceptions, subject to close regulatory supervision, could be (temporarily) thought of where the market cannot (yet) provide that activity or where the activity can be considered as a means to end in the public good. An example for the latter could be the provision of technical analysis services to network users (incl. final customers, distributed generators, prosumers, storage units, electric vehicles charging points) under certain conditions. In such case, Article 23(5) of the e-Directive requires Member States to ensure that charges imposed by regulated entities that provide data services are reasonable and duly justified.

Finally, the rules on access to and storage of data as well as the processing of personal data need to be compliant with relevant Union law, e.g. the GDPR or the Network and Information Systems Security Directive (NIS-Directive) and need to take into account cyber security provisions as described in Box 6.

Box 6: A European framework for cyber security and data protection

Cyber security is considered crucial for economic and social safety in Europe and thus among the highest priorities for the EU. In its recommendation on cyber security in the energy sector, the European Commission (EC 2019a) identifies three main issues, namely real-time requirements, cascading effects and the combination of legacy and state-of-the-art technology. Key success factors to deal with these new challenges range from enhancing the capabilities and competences of the personnel involved; to the decisions of NRAs upon cyber security-related expenditure of regulated grid operators; to finding technical solutions to isolate affected components of a grid within an acceptable timeframe in the event of an attack (CEER 2018; EECSP 2017).

Since the adoption of the EU Cybersecurity Strategy in 2013, the EC has been aiming to develop a favourable environment for the digital transformation of the energy sector while acknowledging the importance of cyber security. Key pieces of legislation to create a framework for handling cyber security and data protection are, *inter alia*, the GDPR, the NIS-Directive[57] as well as the Clean Energy Package and European Cyber Security Act (Regulation (EU) 2019/881).

The GDPR applies to all organisations handling personal data electronically, regardless of their size and function. It focuses on protection of personal data; it does not address the content of the information nor prescribes cyber security measures in relation to specific sectors. However, as outlined above, the deployment of smart grids and smart meters requires energy companies to comply with privacy and data protection legislation.

The NIS-Directive concerns security of network and information systems. It enhances the overall level of cyber security across MS through the development of national cybersecurity capabilities, the increase of EU-level cooperation and the introduction of security and incident reporting obligations for companies referred to as 'Operators of Essential Services (OES)' including in the energy sector (EC 2019a). OES are obliged to address cyber security appropriately, i.e. to operate their network and information utilities compliant to defined minimum cyber security standards to be introduced within the national cyber security law. CEER (2018) reports good progress regarding the implementation of the NIS-Directive across MS.

Following a proposal by the EC (2017c), an EU Cyber Security Act (Regulation (EU) 2019/881) was adopted in 2019. The act reinforces the mandate of the European Union Agency for Network and Information and Security (ENISA) so as to better support Member States with tackling cybersecurity threats and attacks. It also establishes an EU framework for a one-stop shop for cybersecurity certification for products, processes and services that will be valid throughout the EU.

Specific provisions on cyber security for the electricity sector are also laid out in the Clean Energy Package. The Regulation on risk preparedness stresses the need to properly assess all risks, including those related to cyber security and proposes to adopt measures to prevent and mitigate those identified risks. The e-Regulation (Art. 59) provides for the adoption of technical rules such as a new network code on sector-specific rules for cyber security aspects of cross-border electricity flows, on common minimum requirements, planning, monitoring, reporting, and crisis management. At the 2019 European Electricity Regulatory Forum (Florence Forum), the EC (2019b) listed cybersecurity as one of three legislative priorities.[58] A working group established by the EC in 2017 is already in the process of preparing the ground for a new network code on cyber security (Twohig 2019).

[57] Directive (EU) 2016/1148 concerning measures for a high common level of security of network and information systems across the Union.

[58] The other two priority areas are demand side response pursuant to Art. 59 of the e-Regulation and interoperability requirements and procedures for data pursuant to Art. 24 of the e-Directive.

2.2 New EU legislation: Getting our act together on the EU interoperability acts

This part of the deliverable discusses interoperability of energy services in Europe. It is divided into four sections: After an introduction to the topic and its background (Section 2.2.1), we explore the various dimensions of interoperability (Section 2.2.2), look at existing experiences with interoperability in the energy and the healthcare sector (Section 2.2.3) and discuss governance of interoperability (Section 2.2.4).

This part of the deliverable was published an FSR Policy Brief in July 2020 (Reif and Meeus 2020). In May 2020, and as part of the preparatory work, FSR/EUI presented the Policy Brief at the Florence School of Regulation's Policy Advisory Council (closed door event) and discussed the future pathway towards interoperability of energy services in Europe with an expert panel consisting of policymakers, regulators, industry, and other stakeholders. In July 2020, FSR/EUI organised an online debate on interoperability of energy services together with representatives of the TSOs community and industry.[59] In January 2021, FSR/EUI organised an online event in the context of the "FSR insights" series to discuss ongoing research on interoperability with an academic panel consisting of academics from other sectors.[60] In all FSR/EUI online events, the audience is typically composed of academics, TSO-DSO representatives, industry representatives, and regulators.

2.2.1 Introduction

The original European Commission proposal for the recast of Electricity Directive (EU) 2019/944 in the Clean Energy Package included a requirement for Member States to define a common data format and a transparent procedure for eligible parties to have access to energy customer data. The European Commission was entitled to determine by means of implementing acts a common European data format and non-discriminatory and transparent procedures for accessing data that should replace the national data formats and procedures for access adopted by the Member States.[61]

In anticipation of these implementing acts, the European Smart Grids Task Force (ESGTF) was tasked by the European Commission with exploring the potential for an industrial initiative for and the possible scope of a common data format at the EU level.[62] It has been concluded that this format should be:

- compatible with what already exists in the Member States;
- adaptable to handle different time resolutions;
- flexible to support any type of variables and units and to address different use cases implemented in the Member States;
- scalable so as to incorporate new future variables or data; and
- easy to implement with the working knowledge already available in the Member States.

Most importantly, it should not be a single data format but an approach that would allow for compatibility or alignment with the existing systems already decided on in the Member States. The main argument against a single data format concerns the anticipated costs of moving from long-

[59] The recording of the online debate and a summary of the event highlights are available at https://fsr.eui.eu/event/facilitating-interoperability-of-energy-services-in-europe/.

[60] The event page is available at https://fsr.eui.eu/event/digitalization-of-energy-infrastructure-and-data-interoperability-what-can-we-learn-from-telecom-and-healthcare/.

[61] 'Data' is understood to include metering and consumption data as well as data required for customer switching, demand response and other services in accordance with Article 23(1) of Directive (EU) 2019/944.

[62] This paragraph relies on the findings in ESGTF (2016) My energy data and ESGTF (2019) Towards Interoperability within the EU for Electricity and Gas Data Access and Exchange.

established business and IT processes which have been set up to handle traditional retail services such as change of supplier and billing to a new system. The ESGTF argues that even small changes to the existing systems would require dedicated projects and large investments, ultimately resulting in increased costs for consumers.

During the Trialogue negotiations, the national and the common EU data formats were removed from the directive. The final version of the Electricity Directive (EU) 2019/944 requires Member States to "*facilitate the full interoperability of energy services within the Union*" (Art.24(1)).[63] The European Commission is entitled to adopt by means of implementing acts interoperability requirements and non-discriminatory and transparent procedures for access to data that shall be based on existing national practices.

At the European Electricity Regulatory Forum (Florence Forum) in June 2019, the European Commission established interoperability as one of three legislative priorities.[64] It seems probable that multiple implementing acts will be adopted to cover existing retail processes, emerging services based on data sharing and emerging services related to demand side flexibility. Note that implementing acts on interoperability will not be adopted as new network codes.

To get our act together on the EU interoperability acts, we: argue that the acts should be ambitious in addressing the multiple dimensions of interoperability for electricity and gas customer data (section 2.2.2); refer to relevant experiences with interoperability, i.e. the North American Green Button initiative for utility customer data, the ENTSO-E initiative in Europe for electricity market and network data and interoperability experience in the healthcare sector (section 2.2.3); identify governance as a key issue in achieving interoperability of energy services; and provide low and high ambition policy recommendations (section 2.2.4).

2.2.2 **The EU interoperability acts should be ambitious in addressing the multiple dimensions of interoperability**

Interoperability frameworks help to describe the way in which organisations have agreed to interact and exchange information with each other.[65] Such frameworks have not only been developed in the electricity sector but also in other sectors like public administration and healthcare, as is illustrated in Figure 8. While there is no agreement on the exact number of interoperability categories, all frameworks recognise that interoperable implementation can only be successful when agreement is reached across all layers of concern and all the relevant stakeholders are involved in the process. We do not propose an additional framework but identify commonalities across frameworks that need to be addressed to achieve a full interoperability of energy services.

Regulation and policy. Regulatory and/or policy alignment is needed at different geographical levels from the European to the regional, national and local to provide incentives and remove impediments to structures that facilitate interoperability.

[63] In its report My energy data, the ESGTF (2016) describes service interoperability as follows: "*a service developed in one national market could easily be sold in other markets*." An EU definition of 'energy services' is provided in Art. 2(7) of Directive 2012/27/EU on energy efficiency.

[64] See the presentation '4.1_5.1_EC_NC update CACM' by the European Commission, available at <https://ec.europa.eu/info/events/european-electricity-regulatory-forum-florence-forum/meeting-european-electricity-regulatory-forum-florence-2019-jun-17_en>, last accessed 7 May 2020.

[65] Note that both narrow and broad understandings of interoperability exist. A narrow understanding only covers interoperability among information and communication technology (ICT) systems, while in a broader understanding interoperability of ICT systems is the means to the end of enabling organisations to work together more efficiently and effectively. We adopt the latter understanding of interoperability in this paper.

Roles and responsibilities. Responsibilities, i.e. tasks, services and functions, should be allocated to harmonised roles independent of real-world parties and physical implementation in applications, systems and components. This helps to standardise and harmonise information exchange, avoid a lock-in of responsibilities by specific parties and ensures flexibility concerning national implementation and future requirements. Depending on the national context, a role may be allocated to a specific party.

Business processes. Organisations wishing to work together and exchange information are likely to have different internal structures and processes, in terms of both business and IT. They are also likely to use different languages. In addition, the objects of interest, the parties involved in the discussion and the language they use may be very different from layer to layer. For example, while there are policymakers and regulators involved in the highest layer, there are system engineers and developers involved in discussing software artefacts and information modelling in the more technical levels.

Therefore, in a first step and as a fundamental basis for reaching interoperability, terms and definitions need to be agreed upon to reach a 'common language' and thereby the basis for common understanding. In a second step, methodologies are needed to define business goals and align existing business processes or establish new ones across organisational boundaries.

Aligning business processes requires documenting them in an agreed standardised way with commonly accepted modelling techniques, including the associated information to be exchanged. Together, these steps establish a common ground for comparison and ensure that all the parties involved can understand the processes and their role(s) in them. A use-case-driven approach is often adopted. This involves the definition of business use cases at a higher level and system use cases at a more technical level.

Information model, data format and communication protocol. Once the business processes are documented, the focus can shift to the content and structure of the information that is exchanged. Interoperability frameworks typically include the use of common descriptions, i.e. agreed processes and methodologies, to make sure that the format and the precise meaning of exchanged data and information is preserved and understood throughout the exchange process. They also include details of the technology involved in linking systems together, for example how information is transported across multiple communication networks and agreements on the data-transmission medium and the rules for accessing it.

Use of standards. Standards support and help to improve interoperability as they essentially specify an agreement between interacting parties. Since no single standard product will be able to cover all different viewpoints and layers of interoperability, a set or portfolio of standards is typically needed to address well-defined use cases. It is important for frameworks not to mandate or endorse the use of any specific (set of) standards. Priority should be given to open international standards instead of proprietary ones to guarantee the inclusion of all stakeholders in their development, enable their re-use and encourage innovation and supplier competition. Standardisation is not a one-off task and standards are likely to be adapted or substituted as technology changes and evolves.

Interoperability testing. Although they are necessary, standards are not sufficient to achieve interoperability. A framework to test and certify how standards are implemented in devices, systems and processes is fundamental to ensure interoperability and security under realistic operating conditions. Note that conformity with communication standards does not necessarily translate into interoperability among communicating devices and systems due to certain degrees of freedom that developers typically face in implementing a communication standard. Testing therefore needs to cover conformity assessments to meet the requirements of standards and interoperability tests among devices and systems.

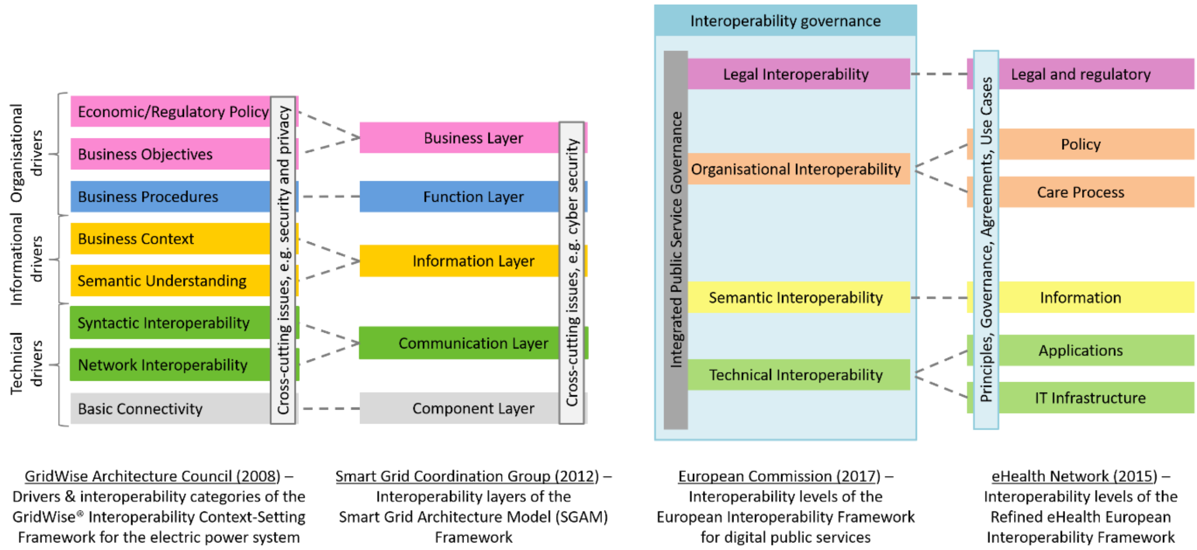


Figure 8: Selection of interoperability frameworks across sectors[66]

2.2.3 Experiences with interoperability in electricity and healthcare

Different use cases can inspire different solutions. In North America the Green Button standard has been used for newly emerging services based on data-sharing and could inspire solutions for these kinds of services in Europe. The ENTSO-E approach has been applied to existing services provided by European TSOs with many legacy systems and might inspire the approach for existing retail services. What has been achieved in the healthcare sector is also a source of inspiration.

The North American Green Button. The Green Button initiative is an industry-led effort launched in the US in January 2012, and it has since been expanded to Canada. The initiative was a response to a White House call-to-action to provide utility customers with easy and secure access to their energy usage information in a consumer-friendly and computer-friendly format via a green button on the websites of utilities for electricity, natural gas and water. Green Button currently essentially covers two capabilities which relate to different parts of the standards it is based on. First, the 'Green Button Download My Data' capability allows customers to download their data in a common XML format that is defined in the ESPI standard for energy usage information communicated from back-end utility data systems. Second, the 'Green Button Connect My Data' capability is based on a data-exchange protocol defined in the ESPI standard for the automatic transfer of data from the utility to a third party based on customer consent.

ENTSO-E. In the implementation of data exchange requirements related to the ENTSO-E Transparency Platform, the Ten-Year Network Development Plan and the electricity network codes and guidelines, ENTSO-E has gained experience with interoperability. For the purpose of this paper, we refer to coordinated capacity calculation, which is a challenging task for three main reasons. It is based on data exchanges among all European TSOs, Regional Security Centres (soon Regional Coordination Centres) and ENTSO-E. It is a cross-domain business process covering both the market and the network domain. Additionally, different Capacity Calculation Regions (CCR) follow different calculation methods (Flow-based and Net Transfer Capacity), which come with different data exchange requirements.

[66] Sources (from left to right): GridWise Architecture Council (2008), GridWise® Interoperability Context-Setting Framework; Smart Grid Coordination Group (2012), Smart Grid Reference Architecture; European Commission (2017), New European Interoperability Framework; eHealth Network (2015), Refined eHealth European Interoperability Framework.

Fundamental to the methodology applied by ENTSO-E is the aim to define a 'common language' as the basic building block for achieving interoperability across CCRs. An 'implementation guide' lists agreed terms and definitions and documents the coordinated capacity calculation business process in a standardised way by means of use case diagrams, roles and their descriptions, activity diagrams and sequence diagrams. Together, these build a generic framework that can accommodate specific local or regional needs, for example by including optional sequences in the sequence diagram to account for data exchanges only required in certain CCRs. Building on these elements, the specific data exchanges are defined in more detail using techniques based on Unified Modelling Language (UML). ENTSO-E uses international and European standards but has also been engaged in standardisation activities to develop technical specifications and standards tailored to the needs of European TSOs.[67]

Table 5 maps the Green Button and the ENTSO-E experience onto the common aspects of interoperability frameworks introduced in the previous section of this paper.

Table 5: Mapping of selected experiences with interoperability in the electricity sector onto common aspects of interoperability frameworks introduced in the previous section of this paper

	North American Green Button	**ENTSO-E[68]**
Regulation/policy	U.S. states including California, Illinois, Colorado, Texas, New Hampshire and New York have Green Button data access and sharing policies in place. Several other states are in the process of reviewing data access policies.	EU Electricity Network Codes and Guidelines
Roles and responsibilities	Covered in the NAESB REQ.21 - *Energy Services Provider Interface* Model Business Practices standard[69]	Harmonised Electricity Market Role Model
Business process	The model for business practices and use cases part of the Green Button standard	Business Process Implementation Guides incl. terms and definitions, business process description, use case diagram, sequence diagrams, etc.
Information model, data format and communication protocol	Common XML format and data exchange protocol as specified in the Green Button standard	Common Information Model (CIM) families of profiles: Common Grid Model Exchange Specification (CGMES) and European Style Market Profile (ESMP), 'harmonised data format' CIMXML and XML, Secure Advanced Message Queuing Protocol

[67] The Implementation Guide for Coordinated Capacity Calculation is available on the ENTSO-E website.

[68] Some elements of the ENTSO-E approach to support network code requirements are described in more depth in chapter 9 of (Schittekatte et al. 2020).

[69] An overview of the website of the North American Energy Standards Board is available at <https://naesb.org/retail_standards.asp>, last accessed on 2 July 2020.

Use of standards	The Green Button standard is based on the North American Energy Standards Board's Energy Services Provider Interface (NAESB ESPI) data standard and its underlying energy usage information model seed standard, the NAESB "PAP10" REQ 18/WEQ19 standard	International and European standards and technical specifications
Interoperability testing	Yes, conformance testing and Green Button certification via the Green Button Alliance Testing & Certification Program	Yes, CGMES conformity assessments and CIM interoperability tests

Healthcare.[70] Interoperability is recognised as being at the same time one of the key drivers of eHealth and one of the greatest challenges in healthcare IT. What has proven successful in the health sector can be described as a multi-step use-case-driven profile-based test-oriented approach to achieving interoperability. A unique element in healthcare interoperability is how testing is carried out. Large-scale international test events are organised on a regular basis and they provide implementers with the possibility of demonstrating component interoperability and compliance with standards or profiles. Testing typically takes place in a neutral environment with the activities covered by a non-disclosure agreement, which allows for cross-vendor collaboration and the removal of barriers to integration that might otherwise need to be addressed ex-post, on site and at the customer's expense already during the product development phase.[71] Note that research has been done that includes a proof-of-concept for transferring the healthcare approach to the energy sector.[72] Note also that we are already experienced in drawing inspiration from the healthcare sector as the Green Button initiative was inspired by the Blue Button, which enables people to access and download their own health information.[73]

[70] We mostly base this paragraph on the Interoperability Guideline for eHealth Deployment Projects, a deliverable of the eStandards project under call H2020-PHC-2014 that provides a comprehensive summary of the approach followed in healthcare. How this approach is implemented in practice can be seen in the example of Integrating the Healthcare Enterprise (IHE). IHE is an international non-profit organisation that is active worldwide to bring together healthcare IT system users and developers to address interoperability issues that impact clinical care. The IHE website is available at <https://www.ihe.net/>, last accessed on 8 May 2020. The term electronic health services ('eHealth') describes the use of information and communication technologies (ICT) in health-related products, services and processes, for example e-prescriptions and electronic health records.

[71] These international test events are the annual IHE Connectathons. Other test events are, for example, Connectathons, organised by the standard-developing organisation High Level Seven International (HL7), and plugtest events, organised by the European Standards Organisation ETSI.

[72] The 'Integrating the Energy System (IES)' research project successfully demonstrated that it is possible to apply methods from healthcare in the energy sector. Further information is available on the project website at <https://www.smartgrids.at/integrating-the-energy-system-ies.html>. See also Gottschalk et al. (2018), *From Integration Profiles to Interoperability Testing for Smart Energy Systems at Connectathon Energy*. Energies 2018, 11(12), 3375. https://doi.org/10.3390/en11123375.

[73] See former U.S. CTO Aneesh Chopra's blog post 'Modelling a Green Energy Challenge after a Blue Button,' available at <https://obamawhitehouse.archives.gov/blog/2011/09/15/modeling-green-energy-challenge-after-blue-button>, last accessed 14 May 2020.

2.2.4 Governance recommendations

We have an existing EU governance for interoperability in energy that covers stakeholder dialogue and standardisation. We could increase the ambition in these two activities, and in addition consider the creation of an EU entity for interoperability management that takes on ownership of the improvement process by formalising best practices and taking responsibilities in terms of implementation monitoring and reporting.

Stakeholder Dialogue. Since its foundation in 2009, the European Smart Grids Task Force (ESGTF) has been the main body for formalised stakeholder dialogue with the European Commission and for sharing national experiences in the area of smart grids. In a low ambition scenario, the European Commission would renew the mandate of the Task Force to advise on emerging topics (e.g. demand side flexibility) and share experiences in Member States.

In a high ambition scenario, the European Commission could aim to centralise the discussion at the EU level by setting up an 'interoperability stakeholder committee' to be co-organised by ACER, the EU DSO entity, ENTSO-E and ENTSOG following the example of the electricity network codes and guidelines. Given the scope of the complex challenge involved in achieving full interoperability of energy services within the Union and the vast differences that currently exist between Member States, it is not unreasonable to assume that the implementing acts will require stakeholder coordination during the implementation phase, or even the development of so-called terms and conditions or methodologies as we have seen with network codes.

The interoperability stakeholder committee would ensure that relevant stakeholders are kept up to date with developments and provided with a forum in which to express their views and feedback throughout the implementation phase. As with the operations network code family, the committee could consist of various technical expert groups that are dedicated to groups of use cases, e.g. existing retail processes, emerging use cases based on data sharing or related to demand side flexibility. The working groups could be tasked with developing and documenting formal rules governing the related data exchanges using commonly agreed methods and tools. Such rules can include common terms and definitions, harmonised roles and responsibilities, generic use cases, activity and sequence diagrams, commonly agreed information standards, data models, profiles and specifications for data exchange and rules and architectures for data aggregation.

European standardisation.[74] For the application of Union harmonisation legislation, the European Commission is entitled to request the European Standardisation Organisations (ESOs) CEN-CENELEC-ETSI to develop harmonised standards. Examples of relevant mandates given to ESOs in the past are M/490 to support smart grid deployment, M/441 in the field of smart metering and M/468 concerning the charging of electric vehicles. ESOs are required to encourage and facilitate appropriate representation of all relevant stakeholders and their effective participation.

In a low ambition scenario, the European Commission could integrate customer data exchange and access into the annual Union work programme on European standardisation. The European Commission may request one or several ESOs to draft a relevant European standard or European standardisation deliverable. An example of an existing standardisation gap seems to be customer consent management and customer authentication.

In a high ambition scenario, the European Commission could formally require ENTSO-E, ENTSOG and the new EU DSO Entity to contribute to standardisation activities relevant to their formal tasks and responsibilities. In addition to standardisation, formal requirements for European associations to contribute to interoperability testing and profiling could also be considered in the future.

[74] European standardisation is governed by Regulation (EU) No 1025/2012.

An EU entity for interoperability management. Experience with interoperability in the healthcare sector has shown that reaching and maintaining interoperability requires a continual improvement process due to changing policies and regulations, emerging use cases and new requirements, the continual development of IT and ICT, rapid changes in the application of components, interfaces and software and continual developments in standardisation. Standardised processes and methods are needed as is described throughout this paper. An entity is needed that takes on the ownership of this improvement process and ensures comprehensive stakeholder participation, including the provision of non-discriminatory access to its results to all relevant stakeholders in the form of, for example, standards, documents or tools. The entity would need to be cross-domain in nature to integrate at least electricity and gas but should also remain open at the frontiers of the traditional energy sector in the light of trends like the internet of things and electric vehicles.

Three groups of tasks can be envisaged. First, formalisation of best practices. We need to re-use and extend best practices with interoperability. The EU entity could be charged with creating and maintaining an 'interoperability repository' as a reference point for national implementation.[75] The repository would serve as a collection of all documents specifying the formal rules governing customer data exchange developed by the working groups of the 'interoperability stakeholder committee' described above. Non-discriminatory access to the repository would need to be ensured for all relevant stakeholders. With increasing use cases that span domains, e.g. flexibility services offered by a (group of) customer(s) to a network operator, the repository could be integrated with similar ones (e.g. ENTSO-E's CIM library) at a later stage.

It could be worth considering H2020 research projects as a multiplier of best practices and a facilitator for the identification of standardisation gaps. As they naturally deal with innovative practices, H2020 consortia could be well-suited to suggest expansions of existing methodologies and models according to the requirements of new use cases, for example the Harmonised Electricity/Gas Market Role Model and the Common Information Model.

Second, implementation monitoring and reporting. It can be assumed that progress towards commonly defined interoperability targets for energy services will advance at varying speeds, given the existing differences at the national level regarding customer data management, access and exchange. With multiple implementing acts being probable, implementation speeds might also differ according to the type of service, i.e. existing, emerging based on data-sharing or emerging related to demand side flexibility. Member States could be required to draft national interoperability action plans defining their pathways towards the interoperability target model and to update them on a regular basis. The European Commission could require the EU entity for managing interoperability to administer and maintain an integrated framework for monitoring, assessing and reporting on progress in implementing the national interoperability action plans using key performance indicators and measurable targets.[76]

Third, interoperability testing. The example of the healthcare sector shows the importance of well-structured easily accessible recurrent testing events for component interoperability and

[75] Some repositories already exist but do not cover the whole spectrum of formal rules suggested here. We know of the ENTSO-E CIM libraries available at <https://www.entsoe.eu/digital/cim/>, last accessed 8 May 2020, and the EPRI Use Case Repository available at < https://smartgrid.epri.com/Repository/Repository.aspx>, last accessed 10 May 2020.

[76] Similar efforts have been made in the area of public administration to foster interoperability of digital public services across Europe. See, for example, the website of the National Interoperability Framework Observatory (NIFO) set up to help share and reuse national experiences, available at <https://ec.europa.eu/isa2/solutions/nifo_en>, last accessed 8 May 2020. Note also that monitoring the gap between national practices and a reference model was recommended by the ESGTF (2019).

standard/profile conformity. An EU entity for interoperability management would be well-placed to provide the necessary neutral environment for large-scale testing events.

Note that in the case of healthcare, the entity that takes on some of these tasks is the non-profit initiative Integrating the Healthcare Enterprise (IHE), which consists of vendors and users of healthcare devices. We are not certain about the feasibility of such an approach for electricity and gas customer data in Europe. However, there are other candidates that could be responsible for all or some of the above-mentioned tasks, for example the Joint Research Centre (JRC), ACER, the EU DSO Entity, ENTSO-E and ENTSOG.

3. Demand-side flexibility

Demand-side response (DR), meaning a change in electricity consumption as a reaction to a price signal, has been acknowledged for many years as a crucial element to enhance the efficiency of the power system. Some of the benefits of DR highlighted in the literature are lower investment needs in power generation, reduction of market power in wholesale markets, avoidance of overinvestment in networks and lower needs for reserves (Burger et al. 2017; O'Connell et al. 2014; Paterakis et al. 2015; Strbac 2008). As DR can respond quickly to changes in system conditions, its value is expected to further increase with more and more intermittent renewables in the electricity generation mix. Lastly, DR is also an important instrument to improve energy efficiency and generally will lead to a reduction in emissions (Dahlke and Prorok 2019; Wohlfarth et al. 2020).

According to the European Commission (2016b), the theoretical European DR potential added up to about 100 GW in 2016 and is expected to reach 160 GW in 2030. In almost all European Member States, the highest share of DR potential exists in the residential sector, especially when considering the uptake of flexible technologies such as electric vehicles and heat pumps. DR is a broad concept. ACER and CEER (2016) and SEDC (2015) provide guidance on how to categorise this concept, and divide DR into implicit and explicit.[77] Changing one's consumption in response to network or market prices is referred to as implicit, or "price-based", DR. When consumers receive incentive or market payments to adjust their loads, they perform explicit DR. The two DR schemes are not interchangeable and may be simultaneously used by consumers in well-designed markets.

In Section 3.1, we discuss the regulatory framework for independent aggregators. Independent aggregators are deemed to be crucial actors to foster the development of explicit DR. We present country experiences and implementation models and draw recommendations on the regulatory framework of independent aggregators. In Section 3.2, we investigate some details regarding the economics of demand-side flexibility through a theoretical model. We also draw recommendations for demand-side flexibility in the use case of distribution network investment savings.

3.1. Taking stock of the regulatory framework for independent aggregators

3.1.1. Introduction

Independent aggregators have been defined in the Clean Energy Package (CEP), more specifically in Art. 2 (19) of the Directive (EU) 2019/944, as *« a market participant engaged in aggregation who is not affiliated to the customer's supplier ».*[78] 'Aggregation' is defined 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 »*. The main purpose of the introduction of independent aggregators is to foster the adoption of explicit DR flexibility programmes by relatively small grid users such as commercial or residential consumers. While in theory both suppliers and independent aggregators could perform the aggregation of loads, suppliers have been relatively slow in taking up this role.

According to the CEP Member States shall enable DR through independent aggregation, yet the CEP only gives principles, not concrete requirements. Each Member State needs to develop a regulatory framework according to the principles described in the aforementioned Directive. Currently, different Member States are implementing their framework. Taking inspiration from such national experimentation, some rules could be detailed by amending existing EU electricity network codes or

[77] SEDC, the European business association for digital and decentralised energy solutions was rebranded as SmartEn (https://smarten.eu/).

[78] For more background about the CEP, please see https://fsr.eui.eu/the-clean-energy-for-all-europeans-package/

through the development of new network codes in the future. Regulation (EU) 2019/943 states in Art. 59(1.e) that a new network code can be developed in the area of DR, including rules on aggregation, energy storage, and demand curtailment rules. Küpper et al. (2020), recognise the regulatory framework around aggregation as an open issue in their study about the priorities for enabling demand side flexibility in the EU. They state that without standardised aggregation frameworks, aggregators will face differing requirements across Member States. These varying requirements could result in higher costs for aggregators to participate in electricity markets as their operational procedures and possibly even their business models have to be adapted, resulting in a barrier to participation. Further, these issues are amplified when cross-border aggregation is considered.

In this section, we contribute to this discussion by focussing on one important element of the regulatory framework around (independent) aggregation, namely on the (contractual) relationship between independent aggregators and suppliers. We divide the discussion into two parts.

The first part discusses whether any imbalances created by the actions of the independent aggregator to the supplier's Balance Responsible Party (BRP) shall be compensated. Art. 49 of the Electricity Balancing Guideline (EB GL) requires that *« Each TSO shall calculate an imbalance adjustment to be applied to the concerned balance responsible parties for each activated balancing energy bid. »* However, whether the same principle should be applied when activated balancing energy bids have been offered by a third-party Balancing Service Provider (BSP) is an open issue. Actions by an independent aggregator can generate a profit or a loss for the supplier's BRP, depending on the imbalance settlement rules in place and on whether the created imbalance is in the opposite direction of the system imbalance or not.

The second part discusses whether suppliers should be compensated when, due to actions of the independent aggregator (in this case a load reduction), they are unable to invoice part of the electricity they had purchased on behalf of their consumers. And, in case a compensation is deemed appropriate, how to design the compensation mechanism? The opposite could also happen, namely that DR is activated to increase load. In such case, the supplier would bill that extra electricity, that it did not purchase. However, this is currently an exception as most of the time consumers are asked to reduce their load. Therefore, suppliers are inclined to claim financial compensation for these losses.

We clarify these two questions and discuss possible answers. Regarding the first question, we find that there is a consensus on how to deal with the imbalances created by independent aggregators' actions. Namely, a vast majority of the products sold by the independent aggregators in different markets are subject to a perimeter correction. This means that the supplier's BRP imbalance is corrected for the change in consumption triggered by the actions of the independent aggregator. This corresponds to an extension of the imbalance adjustment to third-party BSPs and to all markets. The correction is done ex-post, in most cases by the TSO. Regarding the second question, there is no consensus about the compensation between the supplier and independent aggregator. Most academic arguments favour a compensation, and several countries have implemented a compensation model for the supplier. However, the ways of designing the compensation mechanism differs. Generally, three models can be distinguished: the regulated, contracted and corrected model. We introduce these models and briefly discuss their merits and deficiencies.

This section is organised as follows. First, we describe how aggregation can enable DR, followed by a discussion of the role of the independent aggregator. Second, we illustrate the impacts of DR through independent aggregation on the different relevant actors. Third, we discuss whether a supplier's Balance Responsible Party (BRP) shall be compensated for the imbalances created by the actions of the independent aggregator. Fourth, we discuss the need and implementation of a supplier compensation model. After, we highlight three implementation difficulties inherent to the split in responsibilities between the supplier and the independent aggregator. Finally, we formulate a conclusion.

3.1.2. Aggregation and the role of the independent aggregator

In this section, we first describe how aggregation can enable DR by smaller consumers. After, we discuss the role of the independent aggregator.

Aggregation

So far, demand side flexibility has been mainly driven by large consumers. The provision of DR by industry has been a common practice for years. Both implicit and explicit DR schemes can be in place. For example, some factories agreed on dynamic pricing with their suppliers, adapting their consumption depending on market price (implicit DR). Other large consumers have contracted with their supplier or grid operators to curtail their load against incentive payments during peak hours (explicit DR). For a survey, please consult Shoreh et al. (2016).

However, as also mentioned in the introduction of this section, DR is not used at its full potential in Europe. More DR potential can be unlocked among industrial users and DR provision can be opened to smaller grid users such as commercial and even household consumers. More specifically, Gils (2014) finds that around half of the potential for load curtailment can be found at the level of residential consumers. For load increase, this share increases to up to 80 %. As an illustration, Saele and Grande (2011) estimate that in Norway around 4.2 % of peak load could be covered by DR from water heaters. Nistor et al. (2015) describe how domestic smart appliances can provide reserves. This is confirmed by the large share of residential and commercial consumers in the delivery of 22.2 GWh of DR in 2019 under the NEBEF mechanism, one of the explicit DR scheme in France, which is a pioneering country in this regard (RTE 2019a; SmartEn 2019).

The participation of small consumers in DR is enabled by the deployment of smart metering devices. With smart meters it is straightforward to for example implement real-time prices and as such stimulate implicit DR by small consumers. However, to fully exploit the DR potential, explicit DR should also be further developed. For example, DR participation in balancing markets and the newly introduced flexibility markets at local level (see e.g. Schittekatte and Meeus (2020)) is deemed of importance to create sufficient competition. Aggregation provides answers to several important issues faced by small consumers when engaging in explicit DR. We briefly discuss four issues: lack of expertise, consumer engagement, technical requirements and reliability.

First, a large portion of household consumers lack fundamental knowledge about electricity markets and their own consumption patterns (Christensen et al. 2020; Kim and Shcherbakova 2011; O'Connell et al. 2014). Additionally, small consumers often lack technical skills such as reading a smart device or forecasting their behaviour and market behaviour to hedge against risk. Aggregators may offer their support, and, for instance, help consumers navigate through legal documents (Burger et al. 2017; Christensen et al. 2020).

Second, finding the motivations driving consumer' engagement is not a simple task. Their behaviour often deviates from classic economic behaviour, for instance because they give significant attention to comfort (Christensen et al. 2020). Consumer motivations can include money savings but also environmental impacts or energy savings, and these motivations may vary from one household to another. As pointed out in O'Connell et al. (2014) and Good et al. (2017), inertia is a major obstacle to DR providers as consumers are reluctant to deviate from their habits. Automation can be an enabler in this regard as it reduces the required effort of the consumer to a minimum. However, automation is associated with high IT costs and only affordable through economies of scale associated with aggregation.

Third, aggregators bring together small DR potentials and enable them to participate in markets which would have otherwise remained closed to them. Challenging requirements to meet for small consumers are, for example, minimum bid size, symmetric bids and products duration. These requirements stem from the need for standardization, but represent a barrier for smaller consumers, which aggregators can help to overcome (Burger et al. 2017; Good et al. 2017).

Fourth, aggregation of loads reduces the risks faced by the providers of DR. Similar to the diversity effect for aggregation of renewable generation units, the failure of one customer can be mitigated by the ability of another one to increase its load reduction in case automation allows. Importantly, in contrast to traditional conventional generation, the energy delivery by aggregated delivery is not a binary outcome (delivery or no delivery). Instead, there is a higher probability to not exactly deliver what was sold, but there is a much lower probability to deliver a lot less than was sold. Kirby (2007) shows that aggregated loads can be more reliable than a small aggregation of generation units for the same product provision. This entails that the risks for the aggregator's BRP are sufficiently low for aggregated DR to be competitive. Currently, penalties schemes for non-delivery of, for example, balancing energy do not always recognise this inherent benefit of aggregation over large generation units (see e.g. Next Kraftwerke (2020)).

Independent aggregation

In theory, both suppliers and independent aggregators could perform the activation of DR via the aggregation of loads. From a market design perspective, a bundled approach for supply and DR (i.e. the supplier-aggregator model) is the simplest way to implement DR and avoids interference with other market participants. However, in several markets around the world independent aggregators represent the vast majority of DR in markets that they can participate. For instance, in 2019, 82 % of registered capacity for DR has been registered by independent aggregators in the Pennsylvania Jersey Maryland (PJM) power market in the U.S. (PJM 2020). Also, between 2014 and 2017, 70 to 98 % of the DR capacity participating in the Great Britain capacity market did so through independent aggregation (Charles River Associates 2017).[79] The supplier-aggregator model is deemed capable of performing well and encouraged by, for instance, Elering and Litgrid (2017) and NordREG (2016). However, independent aggregators have key features that make them highly suitable to unlock an increasing volume of DR potential. From the literature, we distilled three arguments supporting the advantage of introducing an independent aggregator: the incentives of suppliers, competition and skills.

First, not all suppliers have incentives to offer DR services. Burger et al. (2017) explains that vertically integrated suppliers that own generation units are inherently reluctant to offer DR programmes. The reason being that DR can lead to lower prices and thus shift surplus from the generation to the demand-side. Also, non-vertically integrated suppliers may be unlikely to engage in providing DR services as these services impact their core business. More specifically, suppliers earn money when their customers consume electricity, while aggregators sell flexibility. As such, suppliers' DR services may focus on electricity products that do not impact the sale of electricity, such as Frequency Containment Reserve (FCR) for which availability is sold and energy volumes are generally low.

Second, Good et al. (2017) and He et al. (2013) point out the benefits of having multiple (independent) aggregators competing to provide DR services to consumers, instead of having consumers directly tied to their supplier for DR services. Commercial consumers and households do not have the same appliances and thus not the same technical specificities. Depending on technical requirements and risk averseness, different consumers can be better suited to offer different products provided by different DR service providers. Encouraging specialization, new entry and competition is deemed necessary by several stakeholders, as described in BestRES (2016), ENTSO-E (2015), European Parliament (2017) and NordREG (2016). This is particularly important when retail markets are not sufficiently liquid.

Third, performing aggregation is not a side activity, it requires a dedicated IT infrastructure and inherent skills and knowledge that a traditional supplier might lack. The development of software is

[79] Nouicer et al. (2020) state that the GB capacity market is the most competitive for aggregation, with circa 45 active players.

a key part of the business model of independent aggregators. Sioshansi (2020) shows that several independent aggregators come from the telecommunication sector. Additionally, Bray and Woodman (2019) describe that aggregators sell flexibility in all possible markets and need to make trade-offs, which suppliers are not used to do.

Given these and other considerations, Directive (EU) 2019/944 acknowledges the importance of independent aggregators and includes provisions for allowing them to offer DR services. In Box 7, the most important provisions are gathered. Art. 13(2) states that independent aggregators can operate without the consent of suppliers. Art. 17(3.d) requires aggregators to be themselves balance responsible or contract with a BRP. Art. 17(4) states that aggregators can be liable to pay compensation to other market participants when they offer DR. The terms and conditions of such compensation are to be defined at Member State level, as well as the detailed rules regulating aggregators' activity.

Box 7: Articles in the Directive (EU) 2019/944 in the CEP relevant for aggregators

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.

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.

Art. 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 /943;

(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.

3.1.3. Illustration: impacts of DR activation on the supplier and its BRP

Independent aggregators offer DR bids to markets. Such bid entails a certain reduction (or increase) in consumption of the contracted consumers compared to a baseline. The actions triggered by the independent aggregator impact the consumers' suppliers. Suppliers purchase a certain amount of energy in advance to cover the consumers' expected load and are responsible for having a balanced position in real time.[80] In this subsection, we illustrate how the actions of independent aggregators impact suppliers and their BRPs. For simplicity, we consider that all consumers contracted by the independent aggregator are supplied by the same supplier.[81]

[80] Supplier may also have delegated their balance responsibility to a third party BRP.

[81] When consumers belong to different suppliers, the actions of the consumers triggered by the independent aggregator shall be settled per respective supplier (and the respective BRP) which can create some implementation issues as discussed later in this section.

First, the left part of Figure 9 illustrates a situation without DR. Imagine a supplier purchasing **x** MWh for its consumers for a certain imbalance settlement period (typically 15 minutes or 1 hour). The supplier purchases this volume of electricity either through long-term contracts, or in day-ahead and intraday markets. In case of a vertically integrated supplier (with generation), the supplier can also generate the electricity itself. Due to random deviations, the consumers will finally consume **x+y** MWh. Depending on whether **y** MWh is positive/negative, the supplier will charge **y** MWh more/less than anticipated via the electricity bill to the consumers. The supplier's BRP will be imbalanced by **y** MWh. Typically, the **y** MWh in this example is drawn from a normal distribution with a mean around zero. The better a supplier can forecast the aggregated consumption of its consumers, the smaller the variance of the distribution of random deviations (var_y) will be. Depending on the whole system imbalance during the given imbalance settlement period and the imbalance of the BRPs' portfolio, the BRP will be rewarded or will have to pay the TSO through the imbalance settlement.

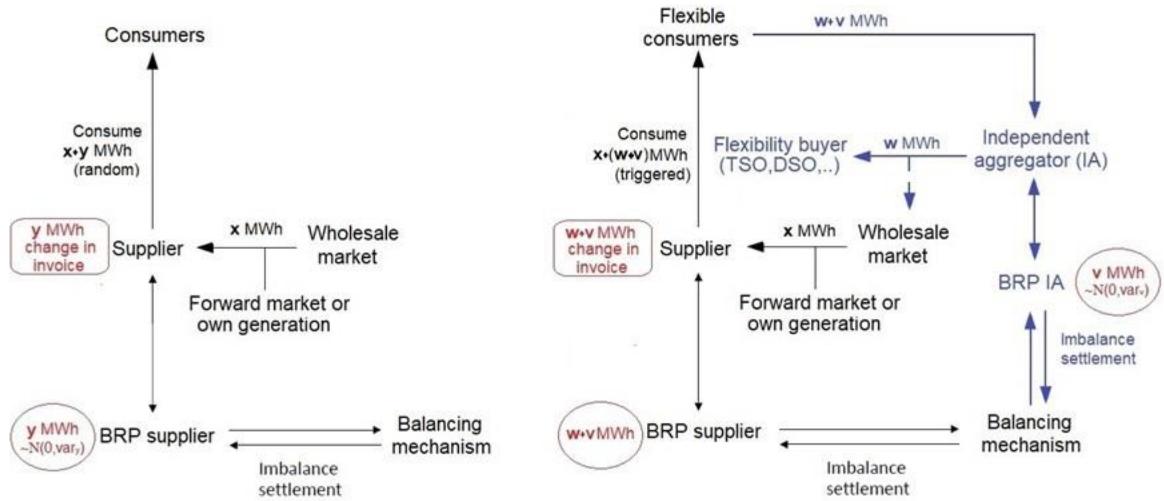


Figure 9: Left- situation without DR. Right- situation with DR via an independent aggregator (IA) without any correction or compensation

Second, the right part of Figure 9 shows a situation with DR. Imagine that during this imbalance settlement period, a **w** MWh DR bid from the independent aggregator is cleared by a market. This bid could be cleared in the day-ahead, intraday, balancing or a flexibility market. To fulfil this bid, the independent aggregator needs to trigger an adjustment in consumption from its contracted consumers compared to the baseline, which we consider to be **x** MWh. In this example, the consumers adjust their consumption with **w+v** MWh, with **v** MWh being the difference between what the independent aggregator requested from the flexible consumers and their actual adjustment in energy consumption compared to the baseline. As stated in Directive (EU) 2019/944 Art. 17(3.d), the independent aggregator is responsible for its imbalances, thus the independent aggregator's BRP will be imbalanced with **v** MWh. **v** MWh is typically drawn from a normal distribution with a mean around zero. The more precise the independent aggregator's control over the consumers' consumption is, the smaller the variance of that distribution (var_v) will be. Please note that, as such, the risk of the random deviation of flexible consumers around their forecasted demand (~N(0,vary)) is transferred to the independent aggregator's BRP (implicit in ~N(0,varv)) during time steps of interventions by the independent aggregator.

Importantly, due to the actions of the independent aggregator, both the supplier and its BRP are impacted. First, the supplier expected to invoice the **x** MWh from its consumers without DR. Due to the actions of the independent aggregator, the supplier invoices **x+(w+v)** MWh. The value of **w+v** is out of control of the supplier. Its absolute value is expected to be larger compared to |**y**| (left part of Figure 9) and it is not necessarily random. Typically, an independent aggregator will ask the consumer to reduce her consumption rather than to increase it. For this example, this means that **w+v** is often a negative number. As such, the independent aggregator's actions are expected to result in a monetary loss for the supplier due to the MWhs the supplier has sourced but cannot invoice. Second, the imbalance of the supplier's BRP will be **w+v** MWh. Like the BRP of the independent aggregator, the BRP of the supplier will be subject to imbalance settlement. Depending on the whole system imbalance, the independent aggregator's intervention can result in a loss or a profit for the supplier's BRP.

Since the independent aggregator is actually selling non-consumed electricity that was sourced by the supplier (**w** MWh in the example), some stakeholders argue that the supplier's BRP shall be corrected and the supplier shall be compensated for the foregone sales. In Section 3.1.4, we discuss the compensation of the supplier's BRP. In Section 3.1.5, we focus on the compensation for the supplier.

3.1.4. Compensation to the supplier's BRP

As illustrated in the previous section, the independent aggregator's actions impact the position of the supplier's BRP. This impact can create either an income or a loss for the supplier's BRP. In that regard, Art. 49 of the EB GL requires that *« Each TSO shall calculate an imbalance adjustment to be applied to the concerned balance responsible parties for each activated balancing energy bid. »* However, whether the same principle should be applied when activated balancing energy bids have been offered by a third-party BSP is an open issue. In this subsection, we first discuss the need to compensate the supplier's BRP. After, we describe in more detail how such compensation is done.

The need for a compensation of the supplier's BRP

Baker (2017) and Voltalis (2020) argue against a compensation of the supplier's BRP because, in their view, the imbalances created by the actions of the independent aggregator will benefit the supplier's BRP financially. This is arguably the case when the accepted DR bid is expected to help balance the system. The supplier's BRP will have an imbalance in the opposite direction of the system imbalance which, depending on the exact implementation of the imbalance settlement mechanism, will result in an income.

However, this argument can be rebutted. First, in the case that, indeed, the independent aggregator's bid is activated to support the balancing of the system and as such the supplier's BRP's imbalance is in the opposite direction of the system imbalance, the TSO would pay both the aggregator for the bid and the BRP through the imbalance settlement mechanism. Such double payment is undesirable from a system point of view as it would lead to a deficit in terms of balancing costs recovered through the imbalance settlement mechanism, which would need to be recuperated via other means. Also, double payments can lead to strategic behaviour. Second, the actions of the independent aggregator will not always result in a "system-favourable" imbalance of the supplier's BRP. The aggregator can also decide to sell its flexibility in the wholesale market or other flexibility markets. In such case, there is no correlation between the imbalance of the supplier's BRP created through the actions of the independent aggregator and the system imbalance.

The perimeter correction

A straightforward way to compensate the supplier's BRP for the actions of the independent aggregator is through a so-called 'perimeter correction'. With a perimeter correction, the imbalance of the supplier's BRP is corrected from the metered volume of energy activated by an independent aggregator's action. This corresponds to an extension of the imbalance adjustment to third party BSPs. The correction is done ex-post, in most cases by the TSO.[82] As such, the supplier's BRP is not held responsible for actions it cannot act on. Today, in many EU Member States a vast majority of the products sold by independent aggregators are subject to perimeter correction (see Box 8 for an

[82] Alternatively, the correction can also be done ex-ante by adjusting the metered profiles of the consumers for the DR activation as in the corrected model described in more detail in Section 3.1.5 and Figure 12 (right).

exception). This is for example the case in Belgium (CREG 2018), France (RTE 2019e), Great Britain (within the TERRE project, DNV GL (2019)), Switzerland (Minniti et al. 2018; Swissgrid 2019) and is planned to be established in Germany (RAUE 2017; Wimmer and Pause 2019) and Slovenia (Borzen, 2019).

Box 8: An exception to perimeter correction– capacity products entailing low (net) energy volumes

When an independent aggregator sells products with capacity reservation payments which entail a low amount of activated energy, such as Frequency Containment Reserve (FCR), a compensation of the supplier and its BRP are deemed unnecessary. For such products, the aim of mitigating losses for suppliers and BRPs can be overweighed by the implementation costs of any compensation mechanism. As also proposed by ENTSO-E (2015) and studied CREG (2016), no perimeter correction is in place for FCR in Belgium (FCR) and Finland (FCR-D) because of low energy volumes are involved and the activation is symmetric (Elia 2019; Pöyry 2018). FCR-D was the first product open to demand-side aggregated bids in Finland and not imposing a perimeter correction was seen as a mean to simplify the process at low cost.

Figure 10 illustrates the perimeter correction. The perimeter of the supplier's BRP is corrected by **w+v** MWh, i.e. the energy activated by the independent aggregator's action. This holds in case the baseline for the independent aggregator's actions is **x** MWh. As described earlier, please note that as such the risk of the random deviation of flexible consumers around their forecasted demand ($\sim N(0,var_y)$) is transferred to the independent aggregator's BRP (implicit in $\sim N(0,var_v)$) during time steps of interventions by the independent aggregator. Three implementation difficulties with the perimeter correction (and any compensation model) are discussed in Section 3.1.6. An alternative to the perimeter correction could be an ex-post financial compensation. However, as also described by DNV GL (2017), such solution would bring complexity in organizing payments to or billings of suppliers' BRPs. It would require different adjustments depending on the markets. A perimeter correction is generally deemed less complex.

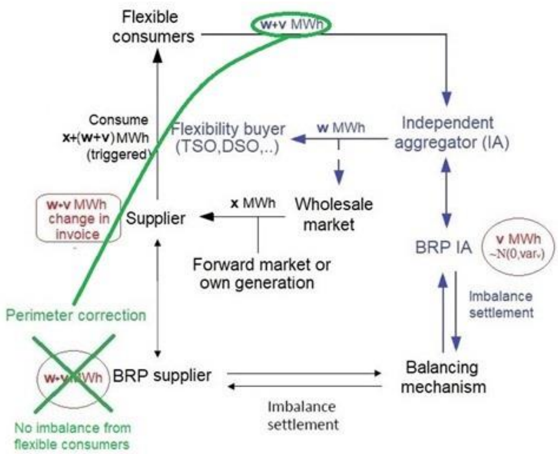


Figure 10: DR via an independent aggregator (IA) with a perimeter correction of the supplier's BRP

3.1.5. Compensation to the supplier

As illustrated in Section 3.1.4, when DR is performed through an independent aggregator, suppliers may be unable to invoice part of the energy they purchased. It could happen that DR is activated to increase load, resulting in the opposite situation. In that case, the supplier would bill electricity that it did not purchase. However, this is currently an exception as most of the time consumers are asked to reduce their load (see also e.g. Alba et al., 2021). Therefore, suppliers claim financial compensation for these losses.

In this subsection, we first discuss the arguments against and in favour of a financial compensation of the supplier. After, we introduce three different supplier compensation models: the regulated, contracted, and corrected model. Lastly, we discuss the three models based on four properties: limiting of potential abuse of power by the supplier, cost-reflectiveness of the compensation, limiting the implementation costs and limiting the transactions costs.

The need for a compensation of the supplier

We start this section by describing three arguments against a compensation of the supplier. After, we discuss the arguments in favour of a compensation.

The observation that serves as the main argument for stakeholders arguing against a compensation of suppliers for the actions of independent aggregators (as Voltalis (2020)) is that the participation of DR in wholesale markets can lead to lower market clearing prices which also benefits suppliers, as illustrated by for example Su and Kirschen (2009). More precisely, even though suppliers lose money because of the energy volumes they cannot invoice to their customers, it is argued that the same suppliers also benefit significantly from the decreased wholesale prices due to DR. According to Baker (2016, 2017), suppliers may be able to keep the benefits of decreased wholesale prices because of imperfections in retail competition. In other words, it is argued that consumer retail prices would remain unchanged while wholesale prices would slightly drop. This reasoning has let some stakeholders such as BEUC (2018) to argue that if compensations were to be established, they should only be introduced when net losses for the supplier are identified. Whether the difference between retail and wholesale prices would materialise and if so, whether the difference was large enough to compensate for the decrease in the volume of invoiced energy is not straightforward. Other stakeholders, e.g. DNV GL (2017), counter this argument by highlighting that a significant share of DR will be sold in balancing or congestion management markets, with limited impact on wholesale prices.

A second argument used to argue against a supplier compensation is that suppliers may not need any compensation as, after some initial learning, they will be able to anticipate independent aggregators' actions. However, as also recognised by NordREG (2020), such learning might take a long time and depends on how difficult forecasting will be in a system with high renewables-based generation. Moreover, adapting their forecasts also means significant costs for the suppliers. Small suppliers or new market entrants might not be able to face these costs and might be compelled to exit retail markets. This would threaten the health of retail markets (DNV GL 2017; NordREG 2020).

A third argument used to argue against the need for a compensation is related to the rebound effect. An example of the rebound effect is that, for instance, when load reduction is associated with lower heating during peak hours, consumers may then increase their heating above their classic consumption in off-peak hours to maintain the same comfort level. With it, the actions of independent aggregators merely impact the timing of consumption and not the total volume of electricity consumed. As such, the need for suppliers to be compensated might be annulled or at least reduced (see e.g. PA Consulting Group (2016)).

Examples of countries in which suppliers are not compensated for the financial losses due to DR through an independent aggregator are Singapore and (currently) Great Britain (DNV GL 2019; EMC 2019).The particular regulatory framework for independent aggregation in Singapore in described in more detail in Box 9.

Box 9: Demand response through independent aggregation in Singapore

In Singapore, both the ancillary services and the wholesale market are open to DR. In the ancillary service market, DR is active through the Interruptible Load (IL) programme. In the IL programme, the consumers can bid capacity they can reduce if asked to do so, directly or through an independent aggregator. The payment is based upon the capacity accepted. The (possibly) activated energy is not paid. When submitted, whether activated or not, the capacity must be available to be activated. If it is not available, the consumer or the independent aggregator will be subject to penalties, even if the plant is not called (EMC 2019). DR is also allowed to participate in the wholesale market through Licensed Load Providers (LLPs). LLPs can aggregate load from different customers without prior consent from their existing suppliers and place bids in the wholesale market. Please note that consumers must contract with the same independent aggregator if they want to participate both in the IL programme and in the wholesale market via LLPs. Bids can be placed for both markets. In that case, the market operator will decide which of the two bids is accepted.

When DR participates in the wholesale market, its remuneration is dealt with according to a separate methodology. DR bids do not receive the market clearing price as in European markets. Instead, two market clearings are performed: one market clearing with and one clearing without DR bids. Only if the wholesale market price is different between the two clearings, a remuneration is paid to the LLPs. More precisely, LLPs receive one third of the total welfare benefits funded through the transmission tariffs. Figure 11 below illustrates this methodology with a numerical example.

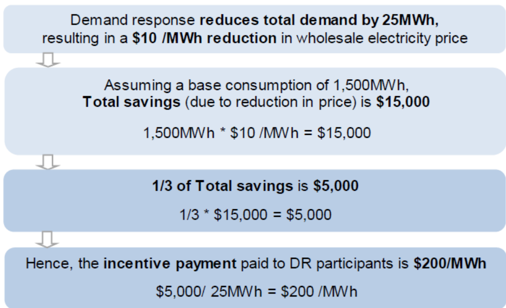


Figure 11: An example of DR remuneration in the wholesale market in Singapore (EMA 2013)

In Singapore, suppliers are not compensated for the reduction in invoiced electricity due to the actions of the independent aggregator. It is argued that by only allocating one third of the benefits that DR bring to the LLPs, suppliers also benefit from the reduction in wholesale market prices. Interestingly, it is possible for suppliers to withdraw from the DR programme to avoid reductions in their invoiced energy. However, the suppliers choosing to do so have to pay the price of the market clearing without DR, plus small charges (EMA 2013).

A last element of the Singaporean DR framework worth highlighting in this context is that LLPs must provide two load schedules, one baseline load schedule without DR and one load schedule with DR. An LPP is only paid under the condition that its load reduction has been consistent with its load schedule with DR. Under 95 % of compliance, the LLP will be given penalties. Penalties for incomplete or non-delivery delivery are common also in the European Member States. In the Singaporean case consumers that are not asked to reduce their loads but deviate from the submitted baseline with more than 5 %, are also charged with penalties. This solution was designed to solve issues around baseline gaming.

Most stakeholders argue in favour of a compensation for the supplier. An important argument for a compensation is that without it, suppliers would bear the risks and costs which enable third-parties to thrive as for example discussed by DNV GL (2017) and Ruby (2017). Crampes and Léautier (2015b) argue for a compensation by stating that "[*T*]*he first necessary layer of regulation for demand response [is]: ex ante, the regulatory authority must impose that consumers are paid the adjustment* *price for not consuming only if they have purchased the energy they resell. Otherwise, demand response will be obviously excessive since consumers would be paid for selling something obtained for free.*" The statement by Crampes and Léautier (2015a) focusses on direct explicit DR by consumers but the rational remains the same for explicit DR through an independent aggregator. Baker (2016) counters this argument by pointing out that today when a consumer decides to reduce or shift its consumption for example because of dynamic pricing, the consumer does not have to compensate its supplier for making these monetary savings. However, the scope of the risks and costs of such sorts of implicit DR might be smaller than explicit DR facilitated through an independent aggregator. An elaborated argumentation in favour of a compensation for the supplier in the case of independent aggregation is provided by Crampes and Léautier (2015a). These authors also argue that not making aggregators pay a compensation for selling something that they did not buy is a disguised subsidy. Most European countries follow this reasoning and have implemented a compensation mechanism for suppliers, examples are Belgium (CREG 2018), France (CRE 2019; RTE 2019d), Switzerland (Minniti et al. 2018; SEDC 2017; Swissgrid 2019) and planned in Germany (RAUE 2017; Wimmer and Pause 2019) and Slovenia (AGEN, 2020; PIS, 2020).[83] In the next section we discuss the different implementations of such compensation models.

Introducing the different models for the supplier compensation

Contrary to the perimeter correction, which is unique and does not include any financial flows, the model to compensate the supplier can take multiple forms.[84] Currently, three main compensation schemes can be distinguished: the regulated model, the contracted model, and the corrected model. Please note that one country can implement several models depending on, for example, the product sold by the independent aggregator, the connection-level (in kV) of the consumers or the technical specificities of the electricity meter.

The first model is the **regulated model**. Under this model, the price that must be paid for each MWh sourced by supplier and activated through a DR bid is determined by a predefined methodology. Such methodology is typically provided, or at least approved, by the National Regulatory Authority (NRA), hence the name of the model. The calculation of the compensation itself can be done in a centralised way, typically by a TSO (in this case often called the central settlement model), or in decentralised way , i.e. directly between the independent aggregator and the supplier according to their regulated (compensation) contract. The compensation aims at covering either the sourcing costs or the foregone revenues of supplier due to the independent aggregators' activity. In the latter case, a margin on top of the estimated sourcing cost is applied. This has been done in Belgium as described in Box 10. Depending on the country, the calculated price can change hourly, as in Belgium, or is more static as in France (see Box 11). In Switzerland, the aggregator is obliged to compensate the supplier for the difference in consumed energy with a payment that is determined by the quarter-hourly day-ahead spot price of the Swiss Electricity Index (SEDC 2017). Also Slovenia is planning to implement the regulated model, the final form of the national legislation is expected to be published in the summer of 2021 (AGEN, 2020; PIS, 2020) as described in Box 11.

Box 10: Demand response through independent aggregation in Belgium

In Belgium, different markets, i.e. the wholesale market, balancing markets and the capacity mechanism, are open or being opened to DR participation through independent aggregation. The

[83] In several other Member States, independent aggregation is not allow (yet) such as for example Denmark, Spain (SmartEn, 2020) and Sweden (DNV GL 2020). When the Clean Energy Package is fully implemented, also independent aggregation shall be allowed in these Member States and the framework around independent aggregation shall be detailed.

[84] The compensation models of the supplier for foregone sales are often referred to as "Transfer of Energy (ToE) models", see e.g. European Smart Grids Task Force (2019). Sometimes, the compensation model of the supplier and the perimeter correction are jointly referred to as the ToE model as in for example DNV GL (2020).

corrected model has been excluded by CREG (2016). The preferred way to deal with the supplier's compensation in Belgium is the contracted model. However, also the regulated model is a possibility in case the independent aggregator and supplier do not come to an agreement about the compensation (CREG 2018). The compensation according to the regulated model (in €/MWh of activated energy) is calculated as follow:

*{[73 % * 1/3 (Cal Y+2 + Cal Y+1 + M+1) + 27 % EPEX spot BE DAM] * 1,05} +/- 5 %*

With :

CAL Y+2 = the mean of daily quotations published by ICE ENDEX over the year two years before the product activation.[85]

CAL Y+1 = the mean of daily quotations published by ICE ENDEX over the year before the product activation.

M+1 = the mean of daily quotations published by ICE ENDEX over the months before the product activation.

EPEX spot BE Day-Ahead Market (DAM) = the quotation published by EPEX spot Belgium on the day ahead market for the hour the product has been activated.

The formula *[73 % * 1/3 (Cal Y+2 + Cal Y+1 + M+1) + 27 % EPEX spot BE DAM]* represents the approximation of the mean sourcing costs according to the CREG. The factor 1,05 corresponds to a typical margin applied by retailers. The asymmetric 5 % factor is positive in case of a downward action and negative in case of an upward activation (CREG 2018). The settlement of the compensation is done in a decentralised way.

Box 11: Demand response through independent aggregation in Slovenia

In Slovenia the first formal independent aggregation model was introduced already in 2019 by the Slovenian market operator (MO) Borzen in order to regulate aggregated flexibility services arising from provisioning of frequency restoration balancing services (aFRR, mFRR) in frame of the then existing national legislation and even before the formal transposition of provisions from the Clean Energy Package into national legislation (PIS, 2019). The employed model is a combination of the contracted and uncorrected model. It offers the possibility but not the obligation to compensate impacts of flexibility activations by the independent aggregator on energy balance of the supplier. Experience has shown that the contract has been employed for compensation on some occasions, and on some not.

Following discussions between Slovenian NRA (Agencija za energijo), MO (Borzen), TSO (ELES), DSO (SODO) and all 5 distribution network companies, a public consultation was launched in 2020 in order to consolidate understanding of all relevant market parties and to timely optimise national regulation on law and sub-law level (AGEN, 2020). As a consequence of the public consultation, Slovenia is currently working towards employment of the regulated model on top of a "split-supply" model (discussed in more detail in Box 14).

Some details emerging from this consultation have already been discussed in proposing improvements for a new law which is transposing Directive 2019/944/EU into national legislation (PIS, 2020). The relevant national legislation is expected to be published in the summer of 2021.

[85] The Intercontinental Exchange (ICE) hosts futures and options contracts for many commodities among which electricity.

The second model is the **contracted model**. In this model, an independent aggregator willing to engage with a consumer needs to agree with the consumer's supplier on a compensation. Importantly, the Directive (EU) 2019/944 sets out a provision for independent aggregators to operate freely from the consumer's existing supplier by stating in Art.13 (2) that: « *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* ». The contracted model implies that the supplier bargains with the independent aggregator. It could be argued that in the contracted model, the consumer concluding an aggregation contract indirectly requires the consent of the supplier. Therefore, one way of interpreting this article would be that if a Member State wants to, it can allow the contracted model. However, alternative compensation models shall also be available wherein there is no need for direct bargaining between the independent aggregator and the supplier, such as the regulated or corrected model.[86] The contracted model is in place in several Member States as an option, for example in Belgium (CREG 2018) encourages the contracted model (see Box 10) and France (the NEBEF mechanism for small consumers (RTE 2019d), see Box 12).

Box 12: Demand response through independent aggregation in France

The different electricity markets, i.e. the wholesale market, balancing markets and the capacity mechanism, are open to (independent) aggregated DR (RTE 2019a, 2019e, 2019d). All three models for the compensation of the supplier are applied in France depending on the voltage-level of the grid user's connection and the smartness of their meters (CRE 2019).

For grid users connected to the transmission network or connected to the distribution network above 36kVA, the corrected model almost always applies. The consumers connected to lower voltage levels by default follow the regulated model but can negotiate a contracted model if they want to. Depending on the technical specificities of the meter and on their supply contract, the compensation under the regulated model (the so-called NEBEF tariff), can differ among consumers. These levels of the regulated compensations (with two prices for peak and off-peak hours) change up to two times a year and are determined by the French national regulatory authority CRE based on the estimated sourcing costs (RTE 2020). RTE has established a centralised platform to facilitate financial flows and disputes settlement for the regulated model.

The third model is referred to as the **corrected model**. In this model, the consumers' load curves are corrected for each activated DR bid. Suppliers' invoicing is then based on the corrected profiles. This implies that suppliers are compensated at the retail price that they have agreed on with their customers. While the regulated model makes no assumption about who is paying the compensation to suppliers, in the corrected model the compensation is typically paid by the consumers through their (corrected) electricity bills and as such there is no direct interaction between the independent aggregator and the supplier. It is however possible that consumers agreed to pass through this compensation costs to the aggregator. However, an issue is that in that case the aggregator would have access to sensitive information, namely the retail price a consumer pays. In that case the aggregator is also engaged in supply activities (but not for that consumer), the aggregator would be able to make a better offer than the existing supplier, distorting competition. The corrected model has been used in France for more than five years for large consumers (CRE 2019) and is planned to be established in Germany (RAUE 2017; Wimmer and Pause 2019).

Table 6 summarises the three models and Figure 12 depicts schematically the interactions between the different actors. Finally, Box 13 provides more discussion about the socialisation of (part of) the supplier compensation.

[86] Further legal analysis is required to clarify the interaction between Art.13 (2) of Directive 2019/944 and the possibility to implement the contracted model.

Table 6: Summary of the three models to compensate the supplier

	Regulated model	*Contracted model*	*Corrected model*
What is the level of the compensation?	Methodology approved by the regulator	Bilateral deal between independent aggregator and supplier	Retail price
Who pays the compensation?	Typically, the independent aggregator	Typically, the independent aggregator	Typically, the consumer via the electricity bill, possibly passed through to the independent aggregator
Examples of countries	Option in France and Belgium, Switzerland	Option in Belgium and France	Large consumers in France, planned in Germany

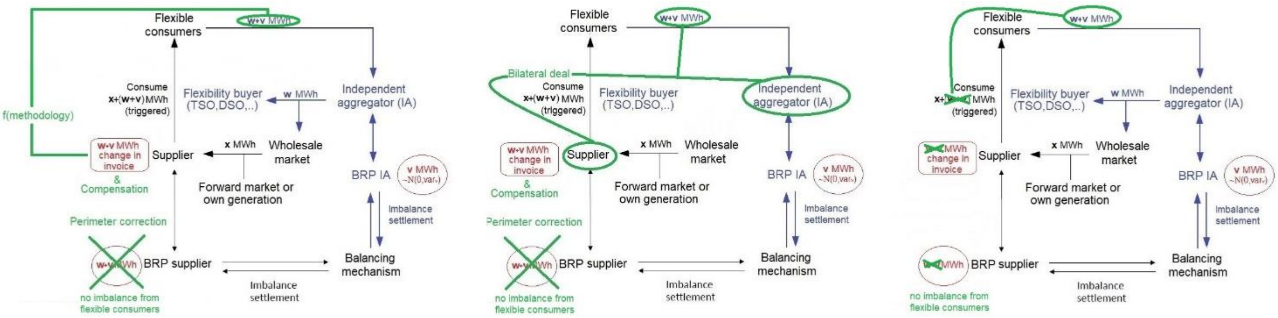


Figure 12: The regulated (left), contracted (middle) and corrected model (right) for the compensation of the supplier and the perimeter correction.

Box 13: Socialisation of (some of) the compensation costs

Several stakeholders (e.g. Baker (2016), Pöyry (2018) and Voltalis (2020)) have argued that if a compensation of the supplier is to be introduced, (part of) the supplier compensation could be socialised. These stakeholders invoke Article 17(4) of Directive (EU) 2019/944 which states that indeed a supplier compensation can be introduced but this compensation shall « *not create a barrier to market entry for market participants engaged in aggregation or a barrier to flexibility*». Concretely, Baker (2016), Pöyry (2018) and Voltalis (2020) claim such socialisation is a necessary implicit subsidy to enable the deployment of independent aggregators. It is argued that if suppliers were to be compensated at DR providers' cost, the profit made would be too small while suppliers would reap most of the benefits in the form of a reduction of wholesale prices. However, implicitly subsidising the independent aggregators' business by socialising part of the compensation costs could lead to suboptimal outcome for the whole system. For example, DNV GL (2017) and NordREG (2020) fear that if the sourcing costs are not internalized by independent aggregators, they could offer DR bids at more competitive prices than suppliers engaged in aggregation. This would distort competition and could lead to excessive DR possibly preventing cheaper solutions from entering the markets (Crampes and Léautier, 2015a; Pöyry, 2018).

An example of the implementation of the socialisation of part of the supplier compensation is France. In France, for the imbalance settlement periods that a consumer reduces its consumption by more than 40 % compared to its baseline, the TSO socialises up to 50 % of the compensation costs (Code de l'énergie Art. L.271-3). These concepts are studied in more detail in USEF (2017).

Discussing the different models for the supplier compensation

The three schemes have been discussed at length by stakeholders and decision-makers. In this section, we discuss four properties of the three models: limiting the potential for abuse of power by the supplier, cost-reflectiveness of the compensation, limiting implementation cost and limiting transaction costs of the model.

First, limiting the potential for abuse of power by the supplier. The model that is deemed to neutralise the potential abuse of power by the supplier is the regulated model. It is obvious that the contracted model, wherein independent aggregators need to reach an agreement with the consumers' existing supplier, could lead to significant bargaining power for large incumbent suppliers. Suppliers could refuse coming to an agreement or ask for a high compensation, which would prevent independent aggregators to operate. Under perfect retail competition, the risk for such behaviour would be lower as consumers are able to switch to suppliers that are willing to sign a contract with independent aggregators, but concerns would remain (Elering and Litgrid 2017; Eurelectric 2015). The risk of abuse of power by suppliers exists also under the corrected model. Even if no contract is required between the consumers' supplier and the aggregator, the billing of the consumers' consumption could lead to discrimination. More precisely, under double billing, meaning that in the electricity bill the electricity consumed is separated from electricity sold as DR, discrimination towards flexible consumers can be incited. According to CREG (2016), to prevent suppliers to identify which consumers are engaged in DR, single billing should be preferred. With single billing, suppliers only know the total amount of electricity that is being purchased per consumer, independent of consumption or DR activation. However, USEF (2017) describes that single billing is complicated, especially regarding the treatment of taxes.

Second, cost-reflectiveness of the compensation. Arguably, the regulated model faces the most difficulties with determining a cost-reflective compensation. Even though a compensation can be calculated with a fine temporal granularity to better reflect the sourcing costs of retailers in peak hours when DR may be activated, it remains uncertain how well the regulated formula that can mimic the sourcing costs or foregone revenues of suppliers (Eurelectric 2015; NordREG 2016). Especially, the consideration of long-term contracts remains challenging. As also argued by NordREG (2016) and Elering and Litgrid (2017), the regulated model necessitates careful regulatory decisions of which the effectiveness is hard to guarantee, and which can be slow to review. In turn, both contracted and the corrected models require fewer regulatory intervention. In the contracted model, the compensation is negotiated bilaterally. Disregarding the existing potential for abuse of power, the compensation might better reflect the actual costs incurred by the supplier due to this flexibility. Under the corrected model, suppliers are compensated at the retail price agreed on with their consumers. The corrected model reflects, by definition, the amount of money suppliers would have invoiced without the activation of DR. Therefore, if metering of the activated energy is consistent, independent aggregators' actions should have no impact on suppliers' revenues. As highlighted by USEF (2017), the corrected model enables, by its nature, to differentiate pricing depending on consumers.

Third, limiting implementation costs. The regulated model requires significant work by the regulator to determine the formula to compute the compensation price and to set up the entire procedure in terms of the financial flows and metering requirements. Compared to the regulated model, the contracted model reduces the burden on the regulator in terms of defining the regulatory framework ex-ante but might require more ex post regulatory monitoring. The corrected model requires the least legislative innovation in terms of setting up the regulation around the compensation. However, significant changes to the legislation governing the invoicing procedure and electricity taxation might be needed, as also remarked by Alba et al. (2021), CREG (2016) and Elering and Litgrid (2017).

Eurelectric (2015) emphasizes metering costs, confidentiality, and transparency as obstacles for the corrected model.

Fourth, limiting transaction costs. In case of the regulated model, once the regulation is in place, transaction costs are limited to the calculation of the compensation and the settlement. This calculation requires information about activated volumes and price indices. Compared to the regulated model, the contracted model increases the transaction costs significantly. In principle, for each consumer-independent aggregator relationship another compensation scheme can be determined. This is less of an issue when an independent aggregator engages with a big industrial consumer but becomes very burdensome when engaging with smaller consumers such as households. Nevertheless, more standardized contracts can be introduced to limit the need to negotiate. In case of the corrected model, as consumers are typically the ones directly compensating their suppliers, they are responsible for negotiating a fair contract with their supplier and with their aggregator. There is a concern that household consumers may refrain from engaging in aggregation, fearing time and costs of such negotiation may outweigh any DR benefits. This view is shared by CREG (2016) stating that in the corrected model consumers are brokers between independent aggregators and supplier, while the aggregator-supplier relationship should not be its worry.

Table 7 summarises the discussion about the three compensation models according to the four highlighted properties.

Table 7: Summary of the properties of the three supplier compensation models

	Regulated model	*Contracted model*	*Corrected model*
Limiting potential for abuse of power by the supplier	++	--	-
Cost-reflectiveness of the compensation	-	+	++
Limiting implementation costs of the model	-	++	-
Limiting transaction costs of the model	+	--	-

3.1.6. General implementation issues

Some technical difficulties remain in the implementation of the perimeter correction and any compensation model. These technical difficulties are inherent to a split responsibility of the supplier and the independent aggregator. We describe three issues: the aggregation of consumers belonging to different suppliers, the rebound effect, and the accuracy of telemetry. In Box 14 an alternative is discussed that would avoid the need for a perimeter correction and supplier compensation, while not burdening the aggregator with all requirements a traditional supplier needs to comply with. Finally, we discuss the split-supply model which also would avoid these implementation issues but which cannot be seen as a direct alternative to a regulatory framework around independent aggregation.

First, NordREG (2016) raises concerns about the technical feasibility of properly allocating imbalances and compensations to BRPs when one independent aggregator brings together many consumers who have contracted with different suppliers (and respective BRPs). Only the total activated volume by an independent aggregator is visible for the market operator or TSO, not the volumes belonging to each consumer group. It could be argued that the independent aggregator can provide this information separately to the TSO on its own initiative. The question remains, however, whether such metering data provided by the independent aggregator could be used in an official financial settlement between two possibly competing market actors. Mandating independent aggregators to form bids from customers with the same supplier could be an option but enforcing the law would limit the business model of independent aggregators.

Second, another issue is the rebound effect. The rebound effect was already mentioned as an argument to wave the supplier's compensation for the foregone sales but similarly, the rebound effect can impact the effectiveness of the perimeter correction as highlighted by Alba et al. (2021). More precisely, even though the perimeter of the supplier's BRP is corrected for the periods when the independent aggregator activates DR, it could be that due to the rebound effect other hard-to-control imbalances occur in the supplier's BRP portfolio just before or after the DR activation. Broka and Baltputnis (2020) simulate that in the worst-case scenario, the financial impacts of the rebound effect on the supplier are considerable. They also find that burdening these additional costs to the aggregators could significantly diminish or outright suspend their development. However, Broka and Baltputnis (2020) nuance this worst case finding by stating that costs could be more limited as not all technologies will create a strong rebound effect and that the supplier can learn how to best anticipate the rebound effect when being informed about DR activations.

A third issue is the accuracy of telemetry measuring the delivered energy by the independent aggregator. Alba et al. (2021) remark that in case the measurement is incorrect, the supplier's BRP can be impacted by imbalances created by the independent aggregator even with a perimeter correction in place. The same issue holds for the supplier compensation if the (perceived) delivered energy by the independent aggregator is also used to determine the supplier's compensation.

Box 14: An option to avoid the need for a perimeter correction and supplier compensation

Alba et al. (2021) describe a so-called 'win-win' model where instead of the supplier taking responsibility for imbalances between the flexible consumer's forecast and actual consumption in real time (even with a perimeter correction), the independent aggregator takes this responsibility for those days and consumers for which it sees an opportunity to market the flexibility. The independent aggregator has its own BRP and is responsible for the imbalance of the program communicated to the TSO. After, the TSO communicates this program to the affected suppliers, which remain responsible for procuring the energy for all customers, including those that are managed by an independent aggregator. As such, the suppliers can adjust their procurement based on schedules communicated by the independent aggregator to the TSO and the need for a compensation is avoided. It is proposed to transfer the balance responsibility of the flexible consumers to the independent aggregator for a full day to capture the impact of the rebound effect. More details can be found in Alba et al. (2021). A potential difficulty with this approach would be that when independent aggregators are active in near real-time markets, such as balancing energy or some non-frequency ancillary services, it might be very hard to forecast their exact actions and thus communicate their schedules to the TSOs. Also, this approach would put a higher burden on independent aggregators and as such can be considered less "in the spirit of the CEP".

Please note that the so-called "split supply" model would also avoid these implementation issues but cannot be considered as an alternative to the regulatory framework around independent aggregation. More specifically, Art. 4 of Directive (EU) 2019/944 that states: *"Member States shall ensure that all customers are free to purchase electricity from the supplier of their choice and shall ensure that all customers are free to have more than one electricity supply contract at the same time, provided that the required connection and metering points are established."* Therefore, a possibility would be to allow an aggregator to be the supplier of the consumers' assets used to provide DR, such as an electrical vehicle or a heat pump, but not of the residual (inflexible) load. Importantly, this solution promotes aggregation but once an aggregator is also the supplier at one of the consumers' metering points, this aggregator cannot be treated as independent anymore. Namely, Art. 2 (19) of the Directive (EU) 2019/944, defines independent aggregator as « *a market participant engaged in aggregation who is not affiliated to the customer's supplier*». Therefore, to comply with the Clean Energy Package requirements, also with the split-supply model in place, a regulatory framework has to be created on top of it in order to enable independent aggregation. The split supply model can be interpreted as an interim step in the development of independent aggregation. However, also several practical issues arise, in particular the cost of equipping consumers with additional smart metering devices. Also, even though under such arrangement aggregators might not need to comply with all supplier requirements, the additional requirement compared to a fully independent aggregators might reduce their ability to enter the DR provision market.

3.1.7. Conclusion and recommendations

In Section 3.1, we have first explained why aggregation is important to unlock the existing DR potential and what role an independent aggregator can play. The recently published Clean Energy for all Europeans Package enables the deployment of independent aggregation. Currently, different European Member States are implementing their regulatory framework around independent aggregation. We focused on one important element of the regulatory framework around (independent) aggregation, namely on the (contractual) relationship between independent aggregators and suppliers. We separated the discussion in two parts: the correction of the supplier's BRP and the compensation of the supplier for foregone revenues.

Regarding the correction of the supplier's BRP, based on relevant literature and looking at implementations in different Member States, it can be said that it is generally accepted to correct the supplier's BRP for the change in consumption triggered by actions of the independent aggregator. Namely, a vast majority of the products sold by the independent aggregators in different markets are subject to a perimeter correction. An exception are capacity products with limited (often symmetric) energy activations such as FCR. The correction is done ex-post, in most cases by the TSO, and does not involve financial flows. In case the three implementation issues described in Section 3.1.6 can be addressed or at least mitigated, the extension of the imbalance adjustment to "third-party BSPs" could be clarified and harmonised at EU-level via an amendment to the Electricity Balancing Guideline (EB GL) without much controversy.

In contrast, more discussion arises about the question whether to compensate the supplier for foregone revenues due to actions of the independent aggregator. And if so, how to compensate the supplier. Advocates of DR through independent aggregation stress that the positive externality brought by DR in the form of reduced wholesale prices makes up for the costs incurred by the supplier. Stakeholders on the opposite side of the debate state that not making aggregators pay a compensation for selling something that they did not buy is a disguised subsidy that can distort competition and could lead to excessive DR, possibly preventing cheaper solutions from entering the markets. Without a compensation, suppliers would bear the risks and costs which enable a third-party to thrive. Many European countries with a regulatory framework for independent aggregators in place follow or are intending to follow the latter reasoning and have implemented a compensation mechanism for suppliers. Examples are Belgium, France, Germany (not implemented yet), Slovenia (not implemented yet) and Switzerland.

The model to compensate the supplier can take multiple forms. Currently, three main compensation schemes can be distinguished: the regulated model, the contracted model, and the corrected model. It is important to note that one country, as is the case in Belgium and France, can implement several models. The model can vary depending on for example the product sold by the independent aggregator, the connection-level (in kV) of the consumers or the technical specificities of the electricity meter. We conducted a preliminary assessment of these three models, looking at four properties: limiting the potential for abuse of power by the supplier, cost-reflectiveness of the compensation, limiting implementation cost and limiting transaction costs of the model. No clear winner arises, and each model has its own trade-off. The regulated model limits the potential abuse of power by the supplier and transaction costs but requires significant regulatory intervention which can result in a less cost-reflective compensation and relatively high implementation costs. The contracted model is straightforward to implement and can enable a cost-reflective compensation but can be susceptible to excessive bargaining power of the supplier and can lead to high transaction costs. Finally, the corrected model is, by definition, cost-reflective when properly implemented and requires limited change to the regulatory framework but can also lead to significant transaction costs as instead of having an agreement between the independent aggregator and the supplier, the consumer becomes the broker between both. Also, adjustments to the invoicing procedure would be required to avoid discrimination of flexible consumers by suppliers.

It is true that without standardised aggregation frameworks, aggregators will face differing requirements across Member States as noted by Küpper et al. (2020). The varying requirements could result in higher costs for aggregators to participate, resulting in a barrier to participation. Also, aggregators active in different Member States could cross-subsidise the penetration in a nascent market with a compensation mechanism in place with revenues from the aggregation business in other Member States where there is no compensation mechanism. However, currently it seems too early to generalise findings to implement European rules via network codes to further detail this aspect of the regulatory framework around independent aggregation. The priority should be to determine whether we want to enforce a supplier compensation, rather than discussing the details of the compensation model. With many new actors in the power system, such as renewables in the past and more recently energy communities and peer-to-peer trading schemes, the question is the same: How to make existing regulation proportional and support these promising business models without discriminating against other actors or distorting competition? One way of dealing with this issue would be to support independent aggregators, of which the benefit for the system is recognised, through other means that do not require the independent aggregator to compensate the supplier or a socialisation of the supplier compensation.

Besides the regulatory framework around the independent aggregator, other future topics to investigate within the context of the demand-side flexibility network code are market access via distribution grids, baseline methodologies, data exchange requirements and non-delivery penalty schemes. A final point is that while currently EU countries are implementing their regulatory frameworks for independent aggregation, new players are already entering the market. Hardware companies, such as Tesla and Sonnen, are integrating the sale of hardware products with supply and activation of demand response (Electrek 2020; Sonnen 2020). The barriers to entry and possible need for regulation to avoid lock-in effects are important future topics to keep up with this evolution.

3.2. The economics of explicit demand-side flexibility in distribution grids

3.2.1 Introduction

The Clean Energy Package (CEP) Directive (EU) 2019/944 calls on the Member States to develop regulatory frameworks that incentivise distribution system operators (DSOs) to consider the use of flexibility as an alternative to grid expansion. DSOs will have to develop and publish network development plans that make a trade-off between the use of flexible resources and system expansion. There are only a few studies that focus on this trade-off. BMWi (2014), a study for the German energy ministry, finds that allowing DSOs to curtail up to 3% of distributed generation (DG) would save about 40% of the network expansion cost. ENEDIS (2017) considers the costs and benefits of six flexibility options, on both the demand side and the supply side, and finds that they may provide important net gains by 2030. Furthermore, an impact assessment report developed by CE and VVA Europe (2016) for the European Commission estimates that the European Union could save up to €5 billion annually by avoiding distribution investments towards 2030.

In the academic literature, Spiliotis et al. (2016) propose a model that assesses the trade-off between grid expansion and demand and DG curtailment. They find that for a congested 24-node radial distribution network all physical expansions could be avoided with 12% flexible demand. Klyapovskiy et al. (2019) consider flexibility from the demand side and in terms of technical solutions using grid assets and compare them to traditional reinforcement over a period of four years. In this paper (Nouicer et al. 2020b), the focus on the potential of explicit demand-side flexibility. Regulators typically design different schemes for supply-side and demand-side flexibility. The regulatory framework for demand-side flexibility is less developed and is more controversial. Demand-side flexibility is more complicated than curtailing consumption because prosumers can invest in other technologies, such as battery storage and solar PV.

The first contribution of this paper is that it assesses the interaction between implicit and explicit demand-side flexibility. Implicit demand-side flexibility is when prosumers react to price signals triggered by network tariffs. Explicit demand-side flexibility is when the DSO curtails consumers' loads for a certain amount of compensation.

There are many academic papers on network tariff design (e.g. Burger et al. (2020) and Schittekatte and Meeus (2020)) yet they do not look at the interaction between network tariffs and explicit demand-side flexibility. At the same time, the above-mentioned papers on demand-side flexibility do not include network tariffs in their models, leaving a gap in the literature.

The second contribution of this paper is that it discusses the right level of compensation for explicit demand-side flexibility. Many studies focus on the level of compensation for supply-side flexibility but we are not aware of a similar study on demand-side flexibility. The third contribution of this paper is through modelling. We develop a long-term bi-level equilibrium model. The upper level (UL) is a regulated DSO deciding on the network investment and demand-side flexibility levels, and recovering the costs of both via distribution network tariffs. The lower level (LL) consists of consumers, which can be prosumers or passive consumers. Prosumers can invest in solar PV and battery systems. Prosumers react to the network tariffs and to the compensation provided by the DSO for curtailing them. The regulated DSO anticipates the reaction of the consumers when investing in the network and when setting the level of curtailment of passive consumers and prosumers. Network tariffs are set to recover the network costs and the payments made to consumers that have been curtailed.

The Section is structured as follows. In subsection 3.2.2, we introduce the modelling approach. In subsection 3.2.3, we detail the results of a numerical example. In subsection 3.2.4, we summarise our main findings and their policy implications.

3.2.2 Methodology

In this subsection, we first introduce our modelling approach, picturing the game-theoretical model and summarising the relevant academic literature. We then present the mathematical formulation with the different players' optimisation problems and the underlying assumptions.

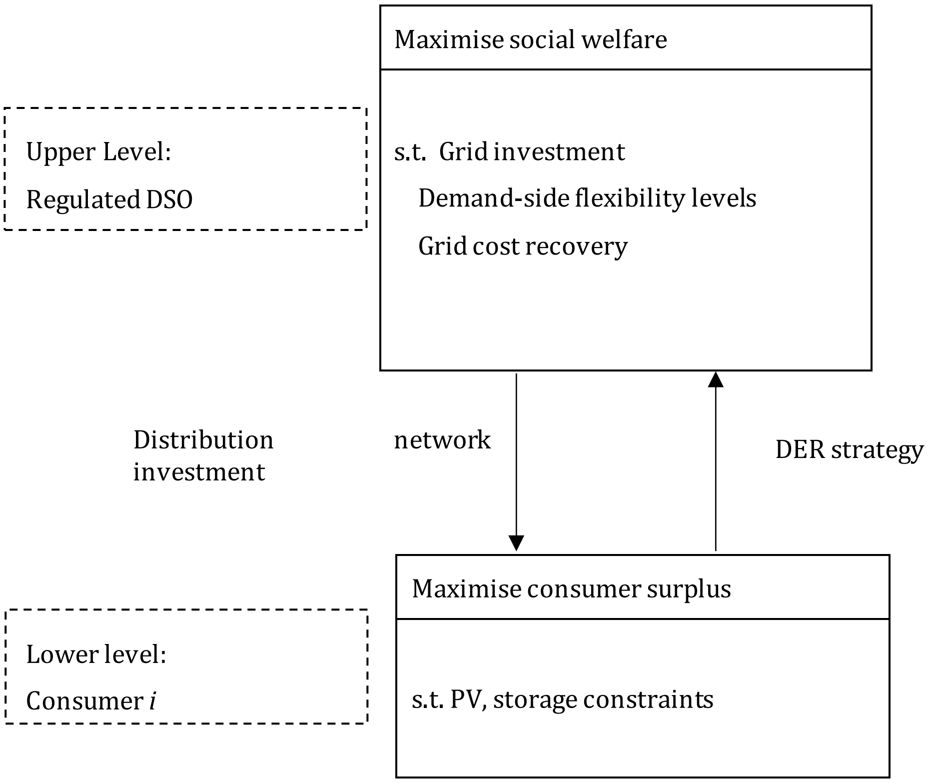
3.2.2.1 Modelling Approach

Our stylised model has a so-called bi-level structure. It is formulated as a mathematical program with equilibrium constraints (MPEC) using Karush–Kuhn–Tucker (KKT) optimality conditions. Being a perfectly regulated DSO, the UL maximises system welfare. In the LL we model electricity consumers, passive consumers and prosumers being active consumers, which maximise their respective surpluses or welfare. The UL feasible set is defined by both a set of constraints and the LL optimisation problem, as it anticipates consumers' reactions to its decisions.

Over the past two decades, the use of bi-level programming has received growing attention among academics. It can address many real-world problems, as they can be formulated as MPECs. Many academic papers and books have focused on this kind of programming problem (e.g. Luo et al. (1996) and Dempe (2002)). In the electricity sector in particular, it has also been increasingly applied. The model used in this paper is an extended version of that used in Schittekatte and Meeus (2020), which in turn builds on Schittekatte et al. (2018). It has the same game-theoretical set-up. Schittekatte and Meeus (2020) apply a cost minimisation formulation that only looks at distribution tariffs as an implicit demand-side flexibility solution. In this paper, we include explicit demand-side flexibility in a welfare maximisation context.

The model allows the regulated DSO to calculate the system welfare and the corresponding level of optimal explicit demand-side flexibility. The regulated DSO also decides on the network charges to send the correct signals to consumers, as is schematised in Figure 13. The consumers are divided into prosumers and passive consumers. Prosumers can strategically decide on the optimal level of PV and storage investment to maximise their surpluses.

Figure 13: Schematic overview of the bi-level model setting



The model output can be interpreted as a generalised Nash equilibrium of a non-cooperative game between the aforementioned agents, i.e. the regulated DSO and the electricity consumers. In the next subsection we present the two optimisation problems. Further details about the problem-solving are presented in Annex A of (Athir Nouicer et al. 2020b).

To solve the MPEC problem, we apply the KNITRO solver in GAMS software (GAMS 2020). The KNITRO options file allows the user to easily set certain computation options, *inter alia* the multi-start heuristic option, which looks for multiple local solutions in order to locate the global solution. We also include tight variable finite upper and lower bounds to reduce computation time.

3.2.2.2 Mathematical formulation

In the following, we first introduce the UL optimisation problem and then the LL optimisation problem.

The upper level: the regulated DSO

The UL problem maximises system welfare. It is represented, in Eq. 1, as the difference between the gross system welfare and the total system costs. Gross system welfare, in Eq. 2, corresponds to the gross welfare from electricity consumption, valued at the Value of Lost Load (VoLL) levels (ACER 2018), to which we add a welfare correction being the potential compensation consumers would receive from the DSO for flexibility services (Eq. 3). Total system costs consist of four components: system grid costs, demand-side flexibility costs, energy costs and DER investment costs (Eq. 4). The regulated DSO decides on: the optimal levels of network investment and demand-side flexibility based on the grid parameters; and compensation. It also anticipates the LL strategy. The trade-off between network investment and the use of flexibility is a topic of growing importance in distribution planning.

$$Maximise \quad GrossSystemWelfare - TotalSystemCosts \tag{1}$$

The electricity demand $d_{i,daytype,t}$ is equal for consumers, i, regardless of whether they are active or passive. Demand profiles are 24h time series, and t takes a value from 1 to 24. However, it differs according to the daytype: normal days or critical days with higher peaks. Their total weight equals the number of days per year. PC_i corresponds to the proportion of prosumers and passive consumers. The compensation, comp, is considered uniform for the different hours and consumer types and $wdt_{daytype}$ is a factor annualising the values.

$$GrossSystemWelfare = \sum_{i=1}^{N} PC_i * \sum_{Daytype=1}^{M} \sum_{t=1}^{T} (d_{i,daytype,t} - qflex_{i,daytype,t}) * VoLL * wdt_{daytype} + WelfareCorrection \quad (2)$$

$$WelfareCorrection = \sum_{i=1}^{N} PC_i * \sum_{Daytype=1}^{M} \sum_{t=1}^{T} comp * qflex_{i,daytype,t} * wdt_{daytype} \quad (3)$$

$$TotalSystemCosts = SystemGridCosts + SystemFlexCosts + SystemDERCosts + SystemEnergyCosts \quad (4)$$

Eq. 5 represents the system grid costs corresponding to the DSO's investment in network expansion. They are assumed to be driven by the coincident peak, meaning that there is no grid at the beginning of the simulation. No sunk costs are therefore included and neither do they have to be recovered. System grid costs are a function of the coincident peak ($CPeak$) and the original demand, $d_{i,daytype,t}$, peak, which is DPeak. The extent to which system grid costs are a function of DPeak or $CPeak$ depends on the WF, that is, the weighting factor representing the network cost driver proxy. It has values ranging between 0 and 1. A WF equal to zero means that individual consumer actions adapting their consumption will not impact grid investment. Conversely, a value of 1 means that a consumer demand reduction of 1 kW will reduce the system peak by 1 kW and consequently reduce grid investments. A similar approach to grid cost representation is used in Schittekatte and Meeus (2020).

$$SystemGridCosts = IncrGridCosts * (DPeak - WF * (Dpeak - CPeak)) \quad (5)$$

The $CPeak$ is determined as the maximum of the demand peak ($CPeakDemand$) and injection peak ($CPeakInjection$) and is represented by Eqs. 6 to 8. $CPeakDemand$ is the maximum value of consumers' withdrawals from the grid ($qw_{t,i}$) minus injections ($qi_{t,daytype,i}$). Both $qw_{t,daytype,i}$ and $qi_{t,daytype,i}$ are consumer decision variables. The same logic applies to $CPeakInjection$.

$$CPeak = max\ (CPeakDemand, CPeakInjection) \quad (6)$$

$$CPeakDemand \geq \sum_{i=1}^{N} PC_i * (qw_{t,daytype,i} - qi_{t,daytype,i}) \quad \forall t \quad (7)$$

$$CPeakInjection \geq \sum_{i=1}^{N} PC_i * (qi_{t,daytype,i} - qw_{t,daytype,i}) \quad \forall t \quad (8)$$

Eq. 9 represents the demand-side flexibility costs, which are the costs of load curtailment. When volume $qflex_{i,daytype.t}$ occurs (in kWh), it is multiplied by its compensation, comp (in €), which is a parameter exogenous to the model. They are then summed for the different time steps and day types and multiplied by the annuity factor.

$$SystemFlexCosts = \sum_{Daytype=1}^{M} \sum_{t=1}^{T} \sum_{i=1}^{N} PC_i * (comp * qflex_{i,daytype.t}) * wdt_{daytype} \quad (9)$$

Prosumers can invest in DERs, which are solar PV and battery systems. Eq. 10 represents the total investment costs in DERs. The decision variable is_i is for solar PV investment (in kWp) installed by consumer i, and ib_i is for investment in batteries (in kWh) installed by consumer i. AICS and AICB are the annualised investment costs for solar PV and batteries respectively. No maintenance costs or degradation of the DER technologies are assumed.

$$DERcosts = \sum_{i=1}^{N} is_i * AICS + ib_i * AICB \tag{10}$$

The system energy costs are calculated using Eq. 11. EBP_t refers to the fixed purchase price of a kWh of electricity. ESP_t is the fixed price received for selling a kWh of electricity.

$$EnergyCosts = \sum_{Daytype=1}^{M} \sum_{t=1}^{T} \sum_{i=1}^{N} (qw_{t,daytype,i} * EBP_t - qi_{t,daytype,i} * ESP_t) * wdt_{daytype} \tag{11}$$

The cost recovery equation (Eq. 12) allows the regulated DSO to recover both the explicit demand-side flexibility and network investment costs from the network tariffs. Network tariffs are typically composed of three components; a capacity cnt (€/kW), a volumetric vnt (€/kWh) and a fixed component fnt (€/consumer). In our modelling, we only allow capacity-based charges as they are deemed to be the most cost-reflective. The LL decides on $qw_{i,daytype,t}$, $qi_{i,daytype,t}$ and $qmax_i$, where $qmax_i$ is the maximum of $qw_{i,daytype,t}$ and $qi_{i,daytype,t}$ over the time series.

$$\sum_{Daytype=1}^{M} \sum_{t=1}^{T} \sum_{i=1}^{N} PC_i * (comp * qflex_{i,daytype,t}) + IncrGridCosts * CPeak = vnt * \sum_{Daytype=1}^{M} \sum_{t=1}^{T} \sum_{i=1}^{N} PC_i * (qw_{i,daytype,t} - qi_{i,daytype,t}) * wdt_{daytype} + cnt * \sum_{i=1}^{N} PC_i * qmax_i + fnt \tag{12}$$

Eq. 13 provides non-negativity constraints for the upper-level optimisation problem.

$$cnt, fnt, vnt, qflex_{t,daytype,i} \geq 0 \quad \forall i, t, daytype \tag{13}$$

The lower level: consumers

In the LL, we model electricity consumers, which can be passive or active. Passive consumers are assumed not to react to flexibility sourcing or network tariffs, while prosumers can invest in DERs to maximise their surpluses. They can also make a trade-off between being curtailed and receiving the corresponding remuneration or investing in DERs to limit the load reduction volumes. A combination of both is, of course, possible. While flexibility allows network costs to be reduced, it harms the consumers' welfare as they value electricity consumption at the VoLL levels.

Each consumer aims to maximise its surplus expressed in Eq.14, which corresponds to the difference between the gross consumer surplus and the costs incurred.

$$Maximise \quad GrossConsumerSurplus_i - Costs_i \tag{14}$$

The gross consumer surplus (Eq.15) corresponds to the value of electricity consumption, that, is every kWh consumed multiplied by the VoLL, to which we add the welfare correction, is the compensation each consumer gets for explicit demand-side flexibility.

$$GrossConsumerSurplus_i = \sum_{Daytype=1}^{M} \sum_{t=1}^{T} (d_{t,,daytype,i} - qflex_{i,daytype,t}) * VoLL * wdt_{daytype} + WelfareCorrection_i \tag{15}$$

$$WelfareCorrection_i = \sum_{Daytype=1}^{M} \sum_{t=1}^{T} \left(comp * qflex_{i,daytype,t} \right) * wdt_{daytype} \quad (16)$$

We divide the costs that every consumer has to pay into three components: energy costs, network charges and DER costs, as is shown in Eq. 17. The calculation of each component is given by Eqs. 18 to 20.

$$Costs_i = EnergyCosts_i + GridCharges_i + DERcosts_i \quad \forall\, i \quad (17)$$

$$EnergyCost_i = \sum_{Daytype=1}^{M} \sum_{t=1}^{T} \left(qw_{t,daytype,i} * EBP_t - qi_{t,daytype,i} * ESP_t \right) * wdt_{daytype} \quad \forall\, i \quad (18)$$

$$Gridcharges_i = \sum_{Daytype=1}^{M} \sum_{t=1}^{T} \left(qw_{t.daytype,i} - NM * qi_{t,daytype,i} \right) * vnt * wdt_{daytype} + cnt * qmax_i + fnt \quad \forall\, i \quad (19)$$

$$DERcosts_i = is_i * AICS + ib_i * AICB \quad \forall\, i \quad (20)$$

The consumer's demand balance is shown in Eq. 21.

$$qw_{i,daytype,t} + is_i * SY_{i,daytype,t} + qbout_{i,daytype,t} - qi_{i,daytype,t} - qbin_{i,daytype,t} + qflex_{i,daytype,t} - d_{i,daytype,t} = 0 \quad \forall\, t, daytype, i \quad (21)$$

In order to solve the problem, the LL optimisation problem is replaced by Karush-Kuhn-Tucker (KKT) optimality conditions. The full sequence of the mathematical process can be found in Athir Nouicer et al. (2020b).

3.2.3 Case study and results

This subsection is divided into three parts. First, we present the case study and justify the parameters used. Second, we present the results. Finally, we conduct a sensitivity analysis.

3.2.3.1 Case study

In this subsection, we introduce the parameters we consider in our model. First, we introduce the demand-related parameters, including the VoLL values. Second, we present the DER parameters, and third we list the grid parameters together with the flexibility compensation. Finally, we summarise the parameters for the reference scenario.

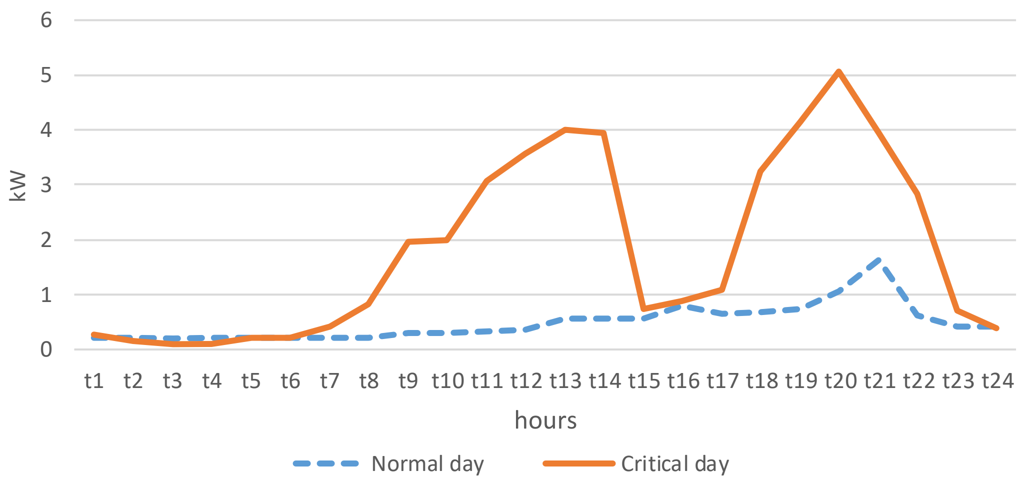
Demand-related parameters

In our model, we consider a 50%-50% distribution between prosumers and passive consumers in the reference scenario. This may seem quite ambitious today. Nevertheless, seeing the current trends in the electricity sector, i.e. decreasing DER investment costs and rising electricity bills together with climate awareness and the movement towards reappropriation of the energy transition, more and more passive consumers may become active.

Both prosumers and passive consumers have similar load profiles. The load profiles we use are divided into two categories: normal days and critical days. The two types of profile are annualised with different weights. In the reference scenario, we use 350 normal days and 15 critical days. The concept of critical days in network planning is analogous to critical peak pricing (CPP) for electricity retail tariffs. For instance, in Australia, CCP tariff schemes assume 10 to 15 days with extreme demand (Norris et al. 2014). In France, 22 days are considered critical in retail tariffs offers within the TEMPO programme (EDF 2019), while for demand curtailment RTE considers 10 to 15 days critical based on weather forecasts (RTE 2019c) and 10 to 25 days based on system voltage (RTE 2019b). Demand-side flexibility schemes can be decoupled from electricity retail offers (EnergyAustralia, (2019) and AGL, (2019)) and operated by system operators to ensure reliable supply in extreme weather events. For instance, CRE (2018) summarises the demand curtailment regulatory framework organised by system operators in France.

We obtain the normal day' load profiles from the 2019 Belgian synthetic load profiles (SLPs) of residential consumers (Synergrid 2019). SLPs reflect the average load, meaning that the peaks are normalised. They are used as input data in the academic literature, as for instance Govaerts et al. (2019). The maximum peak load is found during a winter weekend and is ~1.6 kW. The maximum peak load during weekdays is also in winter and is slightly lower than the peak load at weekends. On critical days, the two daily peaks are magnified. The maximum peak load on critical days is ~5 kW. The high peaks in the critical day' profiles are due to spikes in consumption resulting from weather conditions or other external factors leading to an extensive use of appliances with higher power requirements. Hayn et al. (2014) present an illustration of the peak demand for selected household appliances, such as a dishwasher ~3 kW, an oven ~2.8 kW and a dryer ~2.7 kW. We distribute their use randomly in terms of time, amplitude and duration, with a concentration of use around the two original peaks of normal days, as is shown in Figure 14. In the future, with the integration of electric vehicles and heat pumps it is likely that these technologies will have a huge impact on household' electricity consumption and the load profile peaks. We use a yearly demand of 4000 kWh, which is in the same range as the average residential electricity consumption in Belgium (ENGIE 2019).

Figure 14: Profiles for normal and critical days



Our modelling approach values the possible discomfort felt by consumers related to demand-side flexibility sourcing, which is expressed through the VoLL and the value of lack of adequacy (VoLA) parameters. The VoLA corresponds to a VoLL with one day's notice. Its value is about 50% less than the VoLL in the different Member States. Using different values of the VoLL can therefore be linked to the time of the announcement of a load reduction event to consumers, which is the notice factor. ACER (2018) gives estimated VoLL and VoLA values for the different EU Member States. We consider a VoLL equal to 5.33 €/kWh in our reference scenario. According to ACER (2018), this corresponds to the annual average VoLA in Belgium. VoLL values differ across Europe. The lowest domestic value is in Bulgaria, with 1.5 €/kWh, and the highest is in the Netherlands, with 22.94 €/kWh. Similarly, VoLA values vary among the Member States, from 0.83 €/kWh in Bulgaria to 12.73 €/kWh in the Netherlands.

DER parameters

We consider that prosumers can invest up to 4 kW of solar PV. There is no utility-scale PV and neither are there large battery systems. A European Commission (2017) behavioural study assumes 3.87 kW to be the average size of residential solar PV installations in Belgium by 2030. Prosumers can also invest up to 8 kWh in battery system capacity.

The installation cost of PV is assumed to be 1200 €/kWp, with a lifetime of 20 years and a discount rate of 5%. For instance, in Germany a small rooftop PV (5-15 kWp) costs in the range between 1200€/kWp and 1400€/kWp (Kost et al. 2018). Worldwide, PV investment costs are decreasing, as IRENA (2018) and Solar Power Europe (2018) state. This justifies our choice of PV investment cost projection.

Regarding battery storage, we opt for a 100€/kWh investment cost, with a lifetime of 10 years and a discount rate of 5%. We also use 90% efficiency in charging and discharging and a 2% leakage rate. IRENA (2017) includes a projection of battery storage costs in 2030 of around 140 €/kWh, depending on lithium-ion battery technology. In a JRC report, Steen et al. (2017) state that lithium-ion battery prices were under $140/kWh in 2017 according to different sources. In the US, Tesla has announced that it will reach $100/kWh by 2022.

Grid-related parameters

In our analysis, grid costs are assumed to be 100% driven by the coincident peak. No network is assumed at the beginning of the simulation. The aim is to stress the value of the trade-off between grid investment and flexibility, as flexibility contributes to reducing the coincident peak. To obtain the values of the grid cost function parameters (Eq. 5), we first calculate the 'default' network costs of the consumers modelled. In our setting, $IncrGridCosts$ are 400 €/kW. The network tariffs are capacity-based. In the reference scenario, we use a perfect proxy for the accuracy of network cost drivers: WF =1. This means that tariffs are deemed to be cost-reflective of the system state and that prosumers correctly adapt their profiles to price signals. An imperfect proxy, e.g. 0.5, would mean that consumers will lower their demand at a different time to that needed by the DSO. Introducing an imperfect proxy would also relax the assumption of identical consumer demand profiles (Schittekatte 2019).

Regarding demand-side flexibility compensation, we choose comp = 1€/kWh for the reference scenario. As the procurement of flexibility services has only been being tested recently in the electricity sector, there are not many studies that assess demand-side flexibility compensation. Nouicer and Meeus (2019) list the different pioneering flexibility procurement projects at the distribution level in the EU. One of these is the Piclo project, for which a UKPN (2019) post-tender report indicates the price of the accepted bids in its 2018/19 flexibility tender. The values for utilisation payments range between 0.001€/kWh and 1.28 €/kWh. The minimum bid of 0.001€/kWh includes an availability payment, while the maximum one of 1.28 €/kWh does not. In our model, we only give a utilisation (energy) compensation for demand flexibility. It should be noted that UKPN flexibility bid prices reflect the prices of a voluntary market-based mechanism.

The reference scenario

Based on the assumptions above, in Table 8, we summarise the main parameters in our reference scenario.

Table 8: Parameters in the reference scenario

Parameter	Value
VoLL	5.33 €/kWh (equal to VoLA of Belgium)
Comp	1 €/kWh
Annual demand	4000 kWh
Frequency of critical days	15

Default Load (normal days)	Synthetic Load Profiles (SLP) - Belgium
Incremental network expansion costs	400 €/kW, no sunk grid costs
WF	1, i.e. cost-reflective tariffs
Network tariffs	cnt, its magnitude is decided endogenously for the entire year (no time differentiation)
Solar PV investment cost	1200 €/kWp
Battery investment cost	100€/kWh
Electricity withdrawal price EBP_t	0.08 €/kWh
Electricity injection price ESP_t	0.72 €/kWh

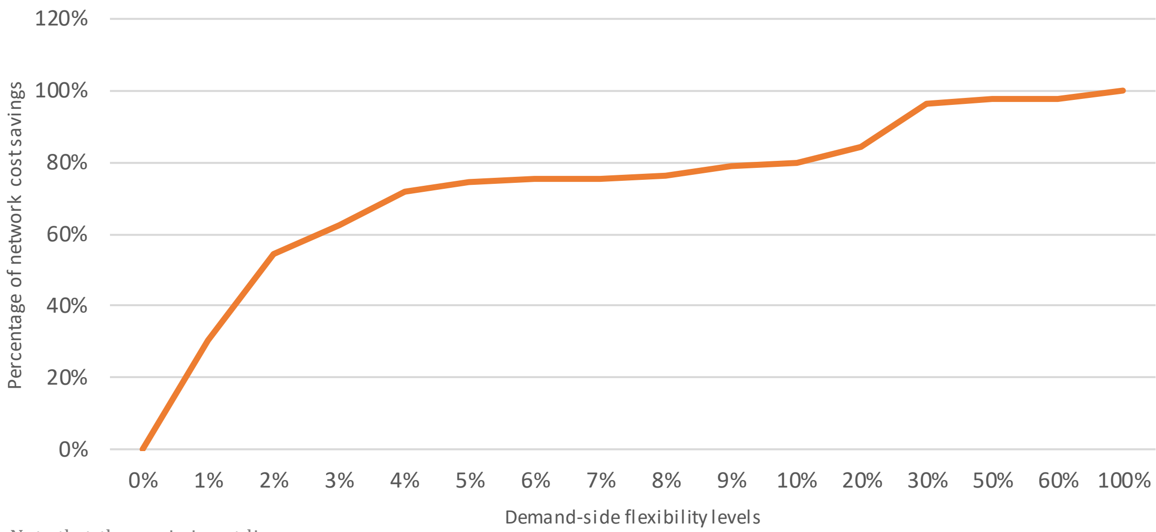
3.2.3.2 Results

In the following, we first present the role of demand-side flexibility in saving distribution network investments. We then assess its impact on system welfare in order to find the optimal demand-side flexibility level. Next, we investigate the impact of network tariffs and explicit demand-side flexibility compensation. Finally, we assess the role of some context-related elements in the demand-side flexibility framework.

Distribution network investment savings

In a first step, we run our model to assess the savings in distribution network investments that the DSO can realise by adopting different levels of demand-side flexibility. To do this, we calculate the network investment in the case where no flexibility is procured. In steps, we then integrate the different demand-side flexibility levels, which are calculated as percentages of the annual demand. This forces the model to solve for the flexibility levels indicated. Figure 15 shows the network investment savings for different demand-side flexibility levels that are procured. It resembles the BMWi (2014) system expansion savings curve, which focuses on DG curtailment.

Figure 15: Distribution network investment savings



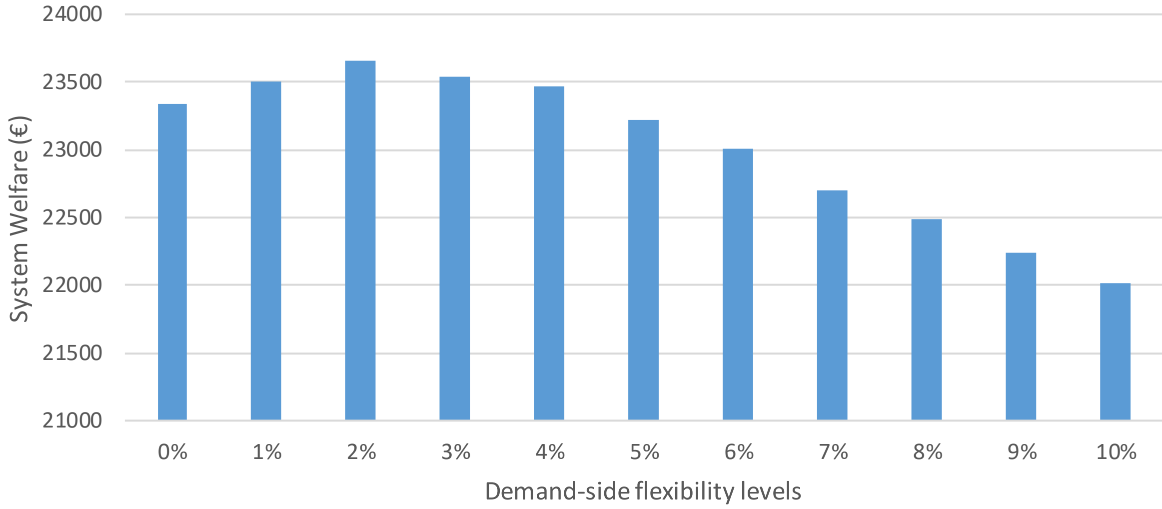
Note that the x-axis is not linear

Network cost savings increase rapidly for demand flexibility volumes below 6 %, and then the curve has a less steep incline. We find that a 3% level of demand-side flexibility allows 62% of distribution grid investment savings and a 5% level allows 75%. The flexibility costs are not taken into account in Figure 15. They are considered as operational expenditures (OPEX), while the savings on grid investment are purely on capital expenditure (CAPEX).

Impact on system welfare

In a second step, we extend our analysis to look at the system welfare (represented in Eq. 1) for different demand-side flexibility levels. This encompasses the introduction of gross welfare, which is measured through the VoLL, valuing the socio-economic loss involved in the non-provision of an electricity unit to the consumer (ACER 2018). In addition, the different system costs (represented in Eq. 4) are considered. The aim is to have a more holistic view of the impact of demand-side flexibility levels on the opportunity costs of electricity consumption and the different associated costs at the system level.

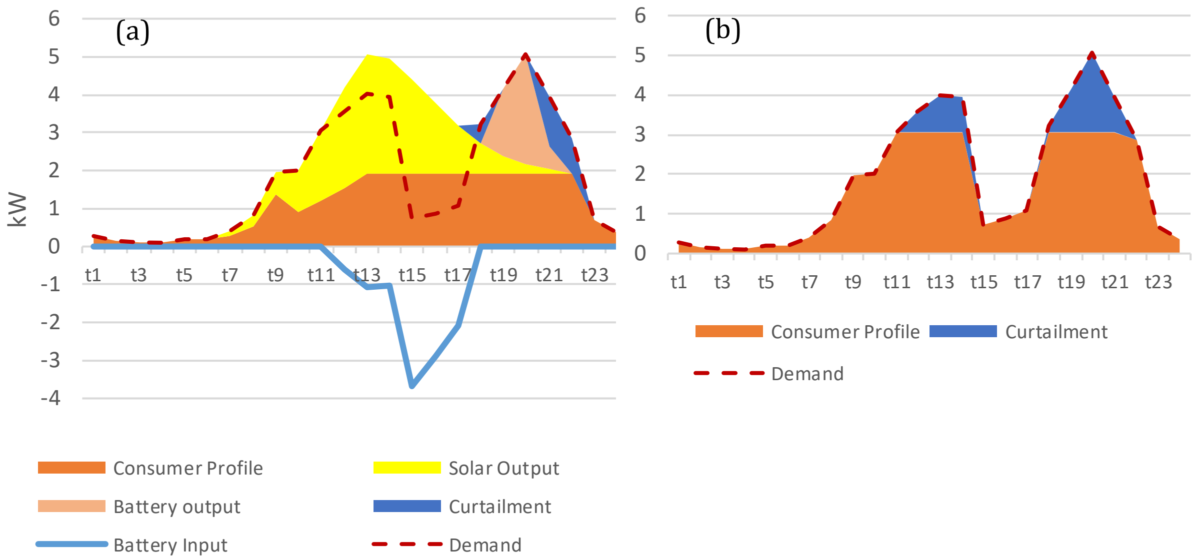
Figure 16: System welfare for different demand-side flexibility levels



As in the previous figure, in Figure 16 we integrate the different demand-side flexibility levels in steps and then plot the system welfare levels. We find that for low levels of demand-side flexibility from 0% to 2% there is an increase in system welfare as demand-side flexibility increases. From 2% onwards, the system welfare starts to decrease. This means that the optimal demand-side flexibility level is between 1% and 3%. The decrease in system welfare for higher demand-side flexibility volumes is driven by two effects: a decrease in gross system welfare and an increase in flexibility costs, and consequently in total system costs.

We then allow the model to decide on the optimal demand-side flexibility level. For the reference scenario, this results in an optimal level of 1.48% demand-side flexibility and €23,816 system welfare, normalised to the (average) consumer. This flexibility allows a €476 annual welfare gain compared to the case where no demand-side flexibility is introduced. Passive consumers are more curtailed than prosumers, with a 65%/35% ratio of the total flexibility level, as is shown in Figure 17. The rationale behind this is that under the reference scenario parameters the DSO relies on implicit demand-side flexibility by transmitting price signals to prosumers to invest in solar PV and batteries, which they use when following the system needs. Passive consumers, in turn, are curtailed more as they do not have alternative ways to generate electricity. However, they are not curtailed to a level that makes their profiles similar to those of the prosumers as this would require higher volumes of curtailment that will severely decrease gross consumer welfare and thus outweigh the savings in total system costs.

Figure 17: Load profiles for the different types of consumers in the reference scenario: (a) prosumers, (b) passive consumers

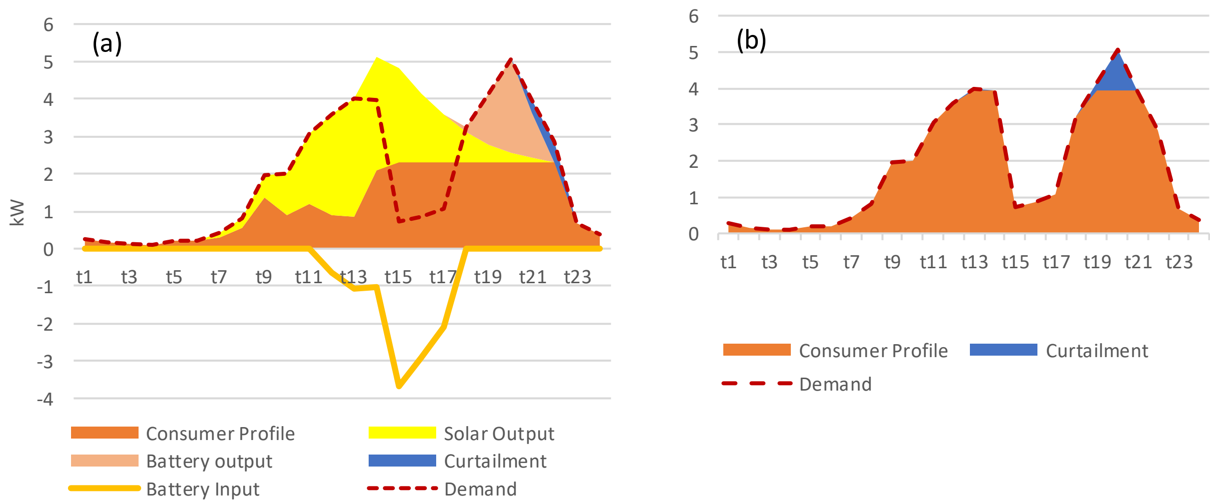


An imperfect proxy for network cost driver, WF=0.5

In order to assess the impact of implicit demand-side flexibility, we introduce partly cost-reflective network tariffs. To do this, we include a 0.5 proxy for network cost drivers, meaning that a 1 kW reduction in the consumer profile peak contributes a 0.5 kW reduction in the system peak. This is also equivalent to having heterogeneous demand profiles among consumers that are optimising their individual profiles. Passey et al. (2017) find that the correlation coefficient between consumer payments under capacity-based tariffs and responsibility for the network peak is very low, at 0.56.

Under this condition, the optimal demand-side flexibility level drops from 1.48% to only 0.35%. The resulting welfare gain drops too, to € 41.8. The rationale behind this is that with an imperfect proxy the potential of explicit demand-side flexibility is limited. Indeed, following their reaction to partly cost-reflective tariffs, the prosumer profile is higher than in the case of a perfect proxy. Therefore, the overall difference between the profiles of prosumers and passive consumers is less pronounced. Consequently, less curtailment is applied to passive consumers. Figure 18 shows the load profiles of both types of consumers for a WF equal to 0.5.

Figure 18: Load profiles for the different types of consumers with WF =0.5: (a) prosumers, (b) passive consumers



The role of prosumers and DER investments

We further expand our assessment by analysing cases with different prosumers' shares and types. We find that when all consumers are passive the optimal demand-side flexibility level stands at 1%, while allowing a €313 welfare gain. With 25% prosumers, the overall optimal demand-side flexibility remains the same, while there is a higher welfare gain. In the case of 100% prosumers, on the other hand, the optimal demand-side flexibility level is 0.34%, allowing only €124. In Table 9 we present the optimal demand-side flexibility levels and the welfare gains for the different cases.

Table 9: Flexibility levels and welfare gains for different shares of prosumers

	100% Passive consumers	25% prosumers / 75% passive consumers	50%-50% Reference Scenario	100% Prosumers
Flexibility level	1%	1.1%	1.48%	0.34%
Welfare (Welfare gain) (€)	23,111 (313)	23393 (338)	23,816 (476)	23,922 (124)

In the case of 100% passive consumers, there is no implicit demand-side flexibility that will change consumer behaviours. The DSO procures 1% of explicit demand-side flexibility. Compared to the reference scenario, the optimal flexibility level is lower. The reason is that in the reference scenario the contribution of implicit demand-side flexibility allows more explicit demand-side flexibility, mainly among passive consumers, and leads to more system cost savings. However, with all passive consumers, this difference between profiles is non-existent. For 100% prosumers, there is 0.34% explicit demand-side flexibility, which is also lower than in the reference scenario. The rationale behind this is that prosumers are able to flatten their consumption profiles in reaction to the network tariff signals sent by the DSO. However, with an already flattened profile there is limited room for further welfare gain, taking into account the effect of the gross consumer welfare loss and the reduction in total system costs. This results in a small welfare gain in the case of 100% prosumers. For the case of 25% prosumers and 75% passive consumers, we find a 1.1% optimal level of explicit demand-side flexibility, while creating more welfare gain than in the case with 100% passive consumers due to the prosumers' contribution to lowering system costs.

Strategic behaviours and the impact of compensation levels

Another parameter that is key in the economics of explicit demand-side flexibility in distribution networks is flexibility compensation. In this part, we run the model for different levels of compensation. We set a low compensation, compared to the reference scenario, at €0.5 and a high compensation equal to the VoLL at €5.33. Table 10 shows the demand-side flexibility levels and the welfare gains for the different compensation levels.

We see that with low compensation the optimal flexibility level decreases, as does the welfare gain, as this compensation is too low for passive consumers. It therefore decreases the optimal flexibility level and the related welfare gain. For a compensation equal to the Voll, the optimal flexibility level remains almost the same. However, the welfare gain is reduced compared to the reference scenario. This is due to strategic behaviour by prosumers, which is shown in their load profiles in Figure 19. We explain this further in the next two paragraphs.

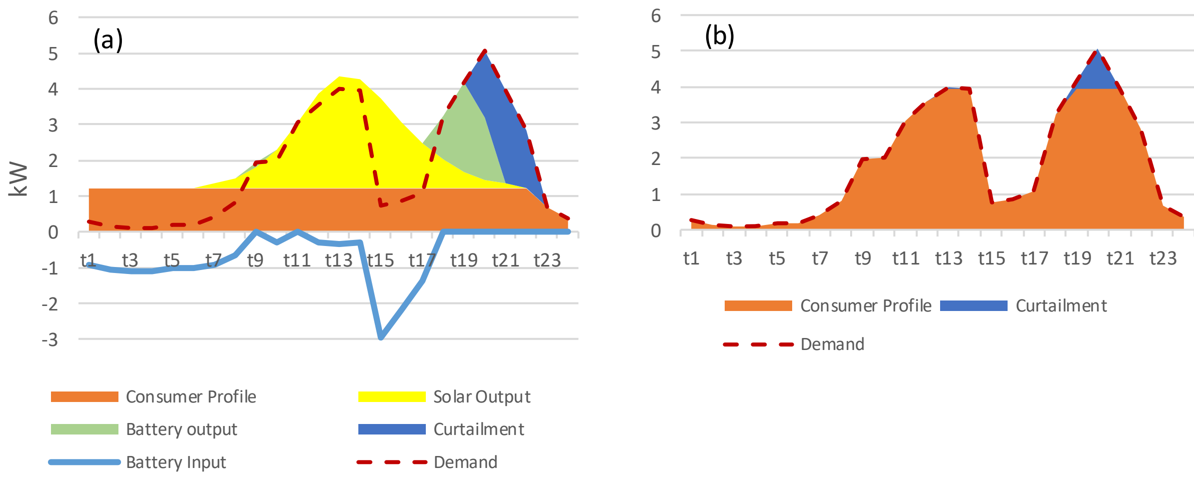
Table 6: Flexibility levels and welfare gains for different compensation levels

Comp	€0.5	€1 Reference scenario	€5.33
Flexibility level	0.8%	1.48%	1.49%
Welfare gain	€239	€476	€152

Compared to the load profile in the reference scenario (in Figure 17(a)), we see in Figure 19(a) that prosumers use their battery output differently. Indeed at t20, which corresponds to the evening peak, prosumers' battery input is 1.7 kW instead of 2.9 kW in the reference scenario. In addition, at t21 there is no battery output from prosumers, compared to 0.6 kW in the reference scenario. Therefore, the DSO has to curtail more prosumers, including at the night peak, even though the network tariffs are cost-reflective. Indeed, with this behaviour prosumers are more curtailed than passive consumers, with a 65%/35% ratio, which is the reverse of the reference scenario.

Another effect that is seen with high compensation is that the prosumer profile has a smaller magnitude in Figure 19(a) than in Figure 17(a). We may think that this is as a positive reaction to cost-reflective network charges. However, if we look again at the battery output during and following the night peak we see that with no or little battery output in these hours there is in fact more curtailment of prosumers.

Figure 19: Load profile for the different types of consumers with Comp= €5.33: (a) prosumers, (b) passive consumers



We may tend to think that compensation set at the VoLL will lead to higher welfare gain. However, we find that this does not happen in the case of prosumers as they value electricity consumption less, which leads to them behaving strategically in order to benefit from the relatively high compensation. The rationale behind this is that prosumers and passive consumers value electricity differently. Therefore, the VoLL for prosumers is lower than for passive consumers. Studies on VoLL estimates segment consumers into different groups based on their economic activity, e.g. domestic consumers and industrial consumers (ACER 2018). However, there is no differentiation between active and passive consumers in VoLL estimations. For instance, ENW (2019) highlights that vulnerable and low-income electricity consumers have higher VoLLs than average. Further effects of the VoLL will be presented in the next section.

Sensitivity results

In this section, a sensitivity analysis is carried out in order to assess the impacts of three context-specific parameters in the demand-side flexibility framework. These parameters are the VoLL, the frequency of critical days and network investment costs. The sensitivity analysis aims to validate the model results and to highlight the extent to which the potential of demand-side flexibility is context-specific.

Sensitivity results: (a) Impact of VoLL levels

In the first sensitivity analysis, we consider two other VoLL values: 2 €/kWh, which is a low VoLL across the EU Member States, and 9.6 €/kWh, which is high.

Table 7: Flexibility levels and welfare gains for different VoLL levels

VoLL	2 €/kWh	5.33 €/kWh Reference scenario	9.6 €/kWh
Flexibility level	4.4%	1.48%	0.2%
Welfare gain	€334.5	€476	€266.4

First, we observe that VoLL levels are inversely proportional to demand-side optimal flexibility levels. For a low VoLL of 2 €/kWh we observe higher levels of demand-side flexibility: 4.4% of the total demand. This is explained by the fact that consumers value electricity consumption less. The lower welfare gain is due to the decrease in gross system welfare due to higher flexibility levels compared to the reference scenario. In addition, as gross welfare is a product of VoLL multiplication, then a lower VoLL will also lead to lower welfare gain. At a high VoLL of 9.6 €/kWh we see the opposite effect, with a low demand-side flexibility level leading to a relatively high welfare gain.

Another element that impacts the potential of demand-side flexibility is the notice factor. This translates into whether consumers are notified (e.g. via email or SMS) about the curtailment event or not. According to ACER (2018), implementing a notice factor reduces the impact of electricity disruption. It also translates into a reduction of VoLL by about 50%, which is then called VoLA. Indeed, in the case of Belgium VoLL is equal to 9.6 €/kWh and VoLA is equal to 5.33 €/kWh. This means that the effect of introducing a notice factor is the same as moving from the third to the second column in Table 11. It therefore results in higher optimal demand-side flexibility and, more importantly, higher welfare gains.

Sensitivity results: (b) The impact of the frequency of critical days

For the second sensitivity analysis, we choose frequencies of critical days from 5 to 104 days a year. The choice of 104 as the maximum frequency corresponds to the frequency of weekend days a year. This is in order to assess how an optimal flexibility volume interacts with the frequency of critical days, *inter alia* when they become as frequent as weekend days.

Table 8: Flexibility levels and welfare gains for different frequencies of critical days

Frequency of critical days	5	15 Reference scenario	104
Flexibility level	2.1%	1.48%	0%
Welfare gain	€612	€476	€0

We observe that the optimal levels of flexibility are inversely proportional to the frequency of critical days. For low frequencies of critical days, there are higher optimal demand-side flexibility volumes. There are two main reasons behind this observation. First, with low frequencies of critical days the regulated DSO would need fewer flexibility volumes to reduce the peaks on the critical days. Second, as we increase the frequency of critical days the total annual demand volume increases. This is natural since the demand during a critical day is higher than on a normal day. Substituting a normal day with a critical one increases the total demand volume. This could be neutralised by reducing the demand on the other normal days. However, we do not change this for practical reasons as changing the normal day profile may create other unwanted effects'. The two above-mentioned effects happen in opposite directions in the two first columns in Table 12. Indeed, for five critical days there is higher welfare gain and higher optimal levels of flexibility, as it is easier to neutralise the critical day' peaks.

Another observation is that in the case with 104 critical days, meaning that they are as frequent as weekend days, the optimal flexibility level is 0%. This confirms the fact that the variation in demand profiles between weekdays and weekends does not result in the use of explicit demand-side flexibility during weekends. Weekend days usually have different consumption levels and peaks. For instance, in the Belgian SLP of Synergrid (2019), weekend days have slightly higher peaks. With a high frequency of critical days higher volumes are needed to reduce peaks to realise system cost savings, as these peaks are very frequent, which in turn will impact gross system welfare. Therefore, it is better to fully build the distribution network and size it to fit the critical day's demand without procuring any flexibility.

Sensitivity results: (c) The impact of network investment costs

Network expansion costs are particularly relevant in DSOs network planning. High network expansion costs can incentivise DSOs to further use demand-side flexibility. In order to assess the impact of this, we consider three scenarios with different incremental network costs, as is shown in Table 13.

Table 9: Flexibility levels and welfare gains for different network expansion costs

Network expansion costs	200€/kW	400 €/kW	600€/kW
Flexibility levels	0.3%	1.48%	3%
Welfare gain	€55	€476	€464

The results confirm that optimal demand-side flexibility volumes increase with higher network expansion costs. With low expansion costs, reinforcing the network is the most logical pathway. Demand-side flexibility of 0.3% is deemed optimal. This will only allow a €55 welfare gain. With low network expansion costs, the regulated DSO will naturally favour network reinforcement as it is not costly. Only a very small part of the consumer's demand is curtailed.

For high network expansion costs, the optimal flexibility levels increase. The rationale behind this is that with high network expansion costs the contribution of demand-side flexibility to system cost savings is more significant. However, the welfare gain is limited due to higher volumes of demand-side flexibility impacting gross system welfare in comparison with the reference scenario.

3.2.4 Conclusions and policy implications

In what follows, we summarise our main findings on the interaction between implicit and explicit demand-side flexibility and the appropriate level of compensation for curtailing demand. In addition, we comment on our sensitivity analysis and indicate the direction of our future research.

First, regarding the interaction between implicit and explicit demand-side flexibility, we found that this interaction strongly depends on the cost-reflectiveness of network tariffs. If network tariffs are cost-reflective, prosumer investments in PV and batteries already take into account the cost of network investments. Explicit demand-side flexibility is then mainly used to target passive consumers that do not respond to tariffs. Passive consumers are typically curtailed during critical conditions when it is cheaper to curtail load than to invest in the network to cover the peak. This, of course, only happens if these critical conditions do not occur frequently. If network tariffs are only partly cost-reflective, explicit demand-side flexibility can also be used to target prosumers to correct their behaviour. However, this correction now comes at a higher cost because the compensation that is provided to prosumers or passive consumers when they are curtailed has to be recovered through the network tariffs. By trying to fix the imperfect signal from the network tariff, we are therefore increasing that signal (and cost). This gives an intuitive explanation of the surprising result that explicit demand-side flexibility is used more in the scenarios with more cost-reflective tariffs. The welfare gains associated with the use of explicit demand-side flexibility are also higher in these scenarios. The policy implication of this result is that we cannot avoid redesigning network tariffs by introducing explicit demand-side flexibility mechanisms.

Second, concerning the appropriate level of compensation to curtail demand, we found that it is very difficult to set an appropriate level of compensation in a context with prosumers and passive consumers. If the compensation is below the VoLL, passive consumers are only partly compensated for their loss. If the compensation is increased towards the VoLL, it becomes so attractive for prosumers that they game the system. They start to use their batteries against system needs, anticipating that they will get curtailed and compensated. They are then generously remunerated at the VoLL, but they only lose load they artificially contributed to. Note that cost-reflective network tariffs cannot stop this behaviour because the signal from the potential compensation can be stronger than the signal from the network tariff in some scenarios. The policy implication of this result is that regulators will have a hard time setting a fixed level of compensation for mandatory load curtailment by DSOs.

Third, we performed a sensitivity analysis. Different countries have different VoLL values. The potential for explicit demand-side flexibility will be higher in countries with a lower VoLL. If consumers know in advance that they will be curtailed, their VoLL is also lower. This implies that explicit demand-side flexibility will have more potential if it can be combined with a notification to consumers to warn them before they are curtailed. Different countries also have different types of critical conditions. The potential of demand-side flexibility is much higher in countries that have critical conditions that are infrequent. If they become as frequent as weekends, it will be cheaper to design the network to handle these conditions. If they are less frequent, it can be cheaper to curtail demand under these critical conditions. This, of course, also depends on the cost of expanding the grid, which can also vary among countries and regions.

Finally, it should be remembered that in this paper we have modelled explicit demand-side flexibility as a mandatory scheme with fixed compensation. The alternative is to let DSOs procure flexibility at a market price. This would allow demand-side flexibility to compete with supply-side flexibility, and would also avoid the difficulty in setting an appropriate level of compensation. It could, however, create new issues with market parties influencing the market price and/or not providing flexibility when the DSO needs it to remedy congestion. This will be the next step in our research and we look forward to analysing it.

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