Ref. Ares(2020)6159462 - 30/10/2020

STORY

added value of STORage in distribution sYstems

Deliverable 8.5
Energy Storage Deployment Handbook

Revision 1
Preparation date .. 2020-10-29 (m66)
Due date 2020-10-31 (m66)
Lead contractor .... VLER
Dissemination level PU

Report edited by Ariana Ramos for Vlerick Business School, with contributions by Leonardo Meeus (Vlerick Business School), Tim Schittekatte (Affiliated with Vlerick Business School), Saskia Broeckx (Affiliated with Vlerick Business School), Luisa Fernandez and Nico Keyaerts (former colleagues at Vlerick Business School working with us during the project).

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 646426

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1 Executive summary

This part of STORY project deals with the business integration of storage into the power system and electricity markets. The objective as described in the description of action is to bring stakeholders a transparent view regarding the ways to roll out storage in the grid. A strong cooperation with the advisory board and projects council is envisaged. Specific objectives are to:

1. Identify business model archetypes for energy storage, looking at the potential users, as well as the value proposition, value chain, and profit model. STORY also looks at the opportunity of using open/collaborative business models and the role of IP arrangements in this respect.
2. Provide information for DSO's and market players on the viability of a certain energy storage business model in combination with a given regulatory and policy framework.
3. Improve the awareness of policy makers, stakeholders, and the general public about the advantages and disadvantages of the main policy options for the deployment of energy storage.
4. Support the policy debate with rigorous analysis of the options, and information about different practices in different countries, such as definition of storage, market and network barriers.
5. Provide recommendations to policy makers and regulatory authorities to set up a framework that will facilitate the deployment of storage.

This document presents the most relevant work done in the work package called 'Business Preconditions', given that each item is a standalone article, conclusions and references per topic are given in each chapter. This handbook first presents a bird's eye view on storage business models and regulation on chapter 3, followed by a summary of the STORY project recommendations. The subsequent annexes present the detailed work that supports and further explains the recommendations set out in this document. Each chapter in the annex represents a study done under the STORY project and is presented in stand-alone chapters published through different media:

Annexes:
Annex 1: STORY demos perspective on storage business models and regulation
Annex 2: The technology provider's perspective on storage business models
Annex 3: The aggregator perspective on storage business models and regulation
Annex 4: The CBA perspective on storage
Annex 5: The Finnish perspective on storage business models and regulation
Annex 6: The distribution tariff impact on storage business models and regulation
Annex 7: The demand response baseline impact on storage business models and regulation
Annex 8: Policy Brief on Regulatory and Business Model Recommendations

After the executive summary and introduction, chapter 3 presents the birds-eye view on storage business models and regulation'. This white paper is the result of a seminar organized for academia and industry in cooperation with the European Association for Storage of Energy. This paper is published on the STORY and Vlerick webpages. Participants from research and industry were invited to present state of the art projects and research on business models and regulation for storage.

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Chapter 4 presents a summary of the regulatory and business model recommendations of the STORY project. The main regulatory discussions identified comprise the legal definition of storage, network tariffs, DSO participation in storage projects, market design, and business model enablers. The recommendations are a result of an iterative process. Vlerick summarized the main regulatory topics under discussion by stakeholders in a webinar in May 2019[1]. The main regulatory items were discussed internally with demo leaders and STORY project participants during a General Meeting in April 2019 and in October 2019. An iterative process with the project participants was then carried out to identify the main lessons learned from the STORY project demos. The identified issues were narrowed down and discussed during a one day meeting in January 2020. Background information and drivers behind each recommendation are presented in Annex 8: Policy Brief on Recommendations.

Annex 1 presents the business models for the STORY demos that were defined in cooperation with the demo leaders and the STORY partners during three internal project workshops during 2018. A mapping of the business models shows the value that the STORY demos create for storage owners, distribution and transmission system operators and other market participants. Annex one and two of this deliverable link directly to the first objective related to identifying business model archetypes. The key take-away of these two sections is the important role of regulation to enable the monetization of the value that storage can create.

Annex 2 presents the technology provider's perspective on business models and storage. This chapter addresses the potential business models to capture value in the business of energy related services, primarily looking at the case of storage systems. The analysis resulted in a mapping of existing businesses in a two dimensional space with on the horizontal axis the customer segments served and on the vertical axis the degree of integration of the value chain. Based on this mapping, four observations have been made. First, there is a potential gap for energy service companies advising customers about the value of storage systems. Second, the majority of businesses focus on deploying assets through selling turnkey solutions and/or by financing the assets to remove the barrier of the significant upfront cost. The deployment is strongly focused to the B2C segment. Third, several business models embrace the sharing economy concept allowing consumer to offer services to other consumers (C2C) or to market players (C2B). Fourth, there seem to be few companies that are oriented towards the B2B segment for optimizing the energy system.

Annex 3 is a paper on 'The aggregator's perspective on storage business models and regulation'. This topic is relevant for storage owners as much of the electricity market is intermediated. Consumers have access to the wholesale and reserves electricity markets through their intermediaries. Traditionally they had access through their retailer as buyers only. Now, as consumers acquire capabilities to inject energy into the network or sell flexibility, they need to sell their energy in the market through an aggregator in order to reach the critical mass and comply with balancing. Participation in markets is key for the business case of storage projects. Storage creates value for many stakeholders, layered business models are the key to moving towards possible business cases. Intermediaries are key actors that can enable that layering of business

[1] A recording of the webinar is available here: http://horizon2020-story.eu/webinar-on-regulation-for-storage/

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models in complex transactions. This paper is also planned to be submitted to a peer-review journal.

Annex 4 presents 'The Cost benefit perspective on storage business models and regulation'. Given that investment in smart grids projects tends to be capital intensive, a cost benefit analysis (CBA) is used to assess and compare on an equal footing the advantages and disadvantages of alternative projects considering the best available information. The CBA of a single smart grid project can then be used to assess the feasibility and viability of that project whereas having a common CBA assessment model allows easy sharing of otherwise fragmented knowledge about which type of smart grid projects performs better in a particular system and market context. Key concerns regarding the implementation of cost benefit analysis were identified as: consistency of data input and reporting, consistency in the calculation methods and models used to monetize cost savings, consistency in scenario analysis and consistency in output reporting.

Annex 5 is a paper on 'The Finnish perspective on storage business models and regulation'. The paper presents case study experiences of several projects where storage is implemented as a service. Finland is an interesting country to study as it was one of the first countries in the world to have adopted smart electricity metering (hourly metering and remote reading) on a full scale. DSO's in Finland are now starting rollouts of next-generation electricity meters, which are capable of receiving, implementing and forwarding load control commands with higher reliability and better response times. This is important enabler for demand response and utilization of battery energy storage systems even at end customer's homes. A literature review complements a series of semi-structured interviews with project developers, the regulator and other market stakeholders.

Annex 6 presents 'The distribution tariff impact on storage business models and regulation', presented at the IAEE conference in 2019. The paper analyses the impact of distribution tariffs on consumer investment and operational decisions. Network tariffs were not designed with storage in mind, they were designed for consumers who were seen purely as 'load', while a consumer with storage assets is sometimes a load for the system and sometimes a generator. Therefore a game theoretical model is developed to test the effect of tariff design on the investment and consumption decisions of final consumers. This topic is also a close up analysis of a regulatory issue, and therefore also linked to the third and fourth objectives of WP8. Three different network tariff designs are evaluated: capacity-based charges, net-purchase volumetric network charges and bi-directional volumetric network charges. Capacity-based network tariffs incentivise consumers to lower their individual peak demand. The two other network tariff designs result in a difference between the value of on-site generated electricity that is self-consumed and electricity that is directly injected back into the network. As such, these network tariff design incentivise self-consumption.

Annex 7 is an academic paper that was presented at the European Energy Markets conference in Slovenia in 2019 treating the topic of 'Consumer Access to electricity markets: the demand response baseline'. This topic was considered as a key regulatory issue for service provision by storage owners to other market parties. The service offered is flexibility provided by storage assets in combination with renewable energy generation systems. Flexibility generally needs to be quantified against a baseline of the 'business as usual' situation. The status without offering

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flexibility needs to be compared to the status after offering flexibility. The gap between the two is starting to be valorised in electricity markets across Europe. This section is a discussion on specific policy aspects related to the deployment of storage and other consumer-side services for electricity markets. It is linked directly to the third and fourth objectives related to providing a detailed policy analysis of the regulatory framework and providing recommendations to policy makers. It is shown in this section that while literature presents advanced statistical methods to calculate the baseline, the most common approaches in practice are simple in nature.

Annex 8 presents the STORY project recommendations on regulation and business models for storage. The main regulatory discussions identified comprise the legal definition of storage, network tariffs, DSO participation in storage projects, market design, and business model enablers. This Annex expands the summary recommendations presented in Chapter 4. For each of the five selected topics, a background discussion is presented followed by the STORY project recommendation.

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2 Introduction

The purpose of this document is to present the output of work package 8 during the STORY project. This work focuses mainly on two tracks: business models and regulation for storage. The business models aspect ties directly into the demo sites of the project: the technology is well on its way to being implemented, now it is time to define the value and revenue models for each study case. The business models description of the demos was built through interactive sessions with the STORY project partners, the STORY advisory board and a seminar with industry and academia during 2018. One important conclusion is that the demos create value that cannot yet be monetized as access to electricity markets is not yet well defined for all prosumers in the demo countries. Business model and regulatory topics often overlap, the regulation in place ought to allow the value to be captured from the services that storage can offer. The results of the work done in WP8 are presented as stand alone chapters that can be read separately giving a multi sided perspectives of the topic.

The authors of this document would like to thank the STORY partners for their participation in each of the sections that constitute this work. The STORY partners have contributed to each section as follows:

- Chapter 3 Bird's-eye view on storage business models and regulation: is written by VLER based on a business models seminar during November 2018 (Brussels), with contributions from PI, VTT, THNK, VLER and external experts.
- Annex 1 on the 'STORY demos perspective on storage business models and regulation': written by VLER based on an internal business models workshop held in November 2018 in Brussels with VITO, THNK, CENER, UL, B9, JR, and with additional input over email iterations by ACT (FLEX), EG, and EXL.
- Annex 2 on the technology provider's perspective on storage business models was written by VLER in the context of the Bridge initiative.
- Annex 3 on 'the aggregator's perspective on business models and regulation' was written by VLER using feedback from an Advisory Board meeting organized by PI (Slovenia, 2017) and with additional input by ACT (FLEX).
- Annex 4 on the 'CBA perspective on storage' was written by VLER and reviewed by JR, VITO and ACT (FLEX).
- Annex 5 'The Finnish perspective on storage business models and regulation' was written in collaboration by VTT and VLER.
- Annexes 6 and 7 have been written by VLER and reviewed by VITO and ACT (FLEX).
- Annex 8 on the 'STORY project recommendations': written based on an iterative process through phone meetings, an in-person workshop (Leuven, 2020), and email iterations with input from VTT, CEN, JR, UL, THNK, PI, VITO, ACT, EXL and VLER.

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3 Bird's-eye view on storage business models and regulation

Saskia Broeckx[a], Ariana Ramos[a], Luísa Fernandez[a], Leonardo Meeus[a,b]
a. Vlerick Business School, Vlerick Energy Centre, Bolwerklaan 21, B-1210 Brussels, Belgium
b. Florence School of Regulation, Robert Schuman Centre for Advanced Studies, European University Institute, Via Boccaccio 121, I-50133 Florence, Italy

3.1 Preface

The electricity landscape is in a state of flux, not least due to the increasing integration of renewable energy sources and distributed generation. In its wake is the growing attention for energy storage, arguably an important part of the renewable energy mix.

How can energy storage be used and integrated into existing power systems, in both residential and industrial environments? This is the key question the STORY project aims to address. Funded by the European Union's Horizon 2020 research and innovation programme, STORY is a 5-year research project analysing new energy storage technologies and their benefits. It features 6 demonstration case studies and involves 18 partner institutions in 7 European countries. One of these partner institutions is Vlerick Business School. In a context where several different actors can use storage assets it is essential to identify business models and regulation that will make energy storage sustainable, which is exactly where our expertise lies. We have taken the lead on the business cases supporting the rollout of electricity storage at the distribution level of the grid; more specifically, on those business cases revolving around the challenges of storage deployment and the interaction between the business models and the enabling market and regulatory context.

On 30 November 2018, Vlerick Business School therefore organised the STORY seminar on Business Models and Regulation for Storage (see Box 1) with the aim of providing a platform for researchers and industry players to meet and discuss the state of the art in research and practice on the integration of storage technologies.

This white paper presents the findings and insights from studies conducted under the umbrella of the STORY project as well as from various experts at the November seminar.

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3.2 Acknowledgements

We also gratefully acknowledge the contribution of the speakers at the STORY seminar:

Mathias Berger (ULiège), Kenneth Bruninx (KU Leuven, VITO and EnergyVille), Patrick Clerens (EASE), Alastair Currie (UK Power Network Services), Niels Govaerts (KU Leuven, VITO and EnergyVille), John Harrison (H2020 STORY and B9 Energy), Yannick Perez (LGI Lab CentraleSupélec), Ksenia Poplavskaya (AIT Austrian Institute of Technology and TU Delft), David Radu (ULiège), Tim Schittekatte (Florence School of Regulation, Université Paris-Sud XI and Vlerick Business School), Alan Thompson (UK Power Network Services) and Servaas Van Den Noortgate (FlexGrid)

Box 1: SEMINAR 30 NOVEMBER 2018: BUSINESS MODELS AND REGULATION FOR STORAGE

Venue: Vlerick Business School – Brussels campus

09.00 – 10.30	Business models for storage
	Moderator: Leonardo Meeus | Vlerick Business School
	Speakers:
	Patrick Clerens | European Association for Storage of Energy (EASE)
	Alan Thompson & Alastair Currie | UK Power Networks Services
	Servaas Van Den Noortgate | FlexGrid
	John Harrison | H2020 STORY & B9 Energy
10.30 – 11.00	Coffee break
11.00 – 12.30	Potential of different storage technologies
	Moderator: Ariana Ramos | Vlerick Business School
	Speakers:
	Yannick Perez | LGI Lab CentraleSupélec
	Kenneth Bruninx | KU Leuven, VITO & EnergyVille
	Mathias Berger & David Radu | University of Liège
12.30 – 13.30	Networking lunch
13.30 – 14.45	Impact of regulation on business case of storage technologies
	Moderator: Leonardo Meeus | Vlerick Business School
	Speakers:
	Tim Schittekatte | Florence School of Regulation, Université Paris-Sud XI & Vlerick Business School
	Niels Govaerts | KU Leuven, VITO & EnergyVille
	Ksenia Poplavskaya | AIT Austrian Institute of Technology & TU Delft
14.45 – 15.00	Closing remarks
	Leonardo Meeus | Vlerick Business School
	Patrick Clerens | European Association for Storage of Energy (EASE)

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3.3 Market potential

Is there a business case for energy storage? Before we can answer this question, we must clarify why we need it. In addition to outlining some of the available technology options, we shall also briefly touch upon alternatives to storage.

3.3.1 Why do we need storage?

To support the transition to a low-carbon economy, the EU's Renewable Energy Directive sets a binding target: by 2030 renewables should at least make up 32% of the energy mix. However, the inclusion of renewable energy sources is not without its challenges.

Our electricity network requires that at any moment in time generation has to equal consumption. The intermittent character of renewables, such as solar and wind energy, now puts this system under pressure as availability and demand are no longer balanced 24/7. Solar energy is only available during daylight hours, while household demand may reach a peak in the evenings. And during the day, clouds may cause solar energy production to fluctuate. Wind turbines, in turn, only generate electricity when the wind blows.

To put things in perspective: the German Advisory Council on the Environment estimated that, in order to cover the maximum peak demand of approximately 86 GW, the installed capacity of renewables should amount to 300 GW, i.e. more than three times the peak demand[2]. Moreover, covering peak demand is not the only issue. Differences between forecasted and actual supply, and between forecasted and actual demand, as well as the resulting real-time differences between supply and demand also need to be addressed. Energy storage is capable of both reducing peak demand and providing flexibility, by balancing real-time differences, as it allows any surplus electricity to be temporarily stored in other forms of energy, in order to be made available again as electricity when needed. The industry has clearly picked up on this opportunity: the European energy storage market is expanding rapidly, having grown 40 to 50% year-on-year, from 0.6 GWh in 2015 to a forecasted 3.5 GWh in 2019[3].

3.3.2 Storage technologies

Talking about energy storage, the first thing that comes to mind is most likely a battery. There are, however, several methods of storing excess electricity until it is needed. Without wanting to be exhaustive, we briefly comment on four storage technologies, three of which were discussed in more detail during the November seminar.

[2] Source: TSO data as of 2016

[3] Source: Numbers include electrical, electrochemical and mechanical storage, with the exception of pumped hydro. European Market Monitor on Energy Storage 2.0 – EASE and Delta-ee

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3.3.3 Pumped hydro storage

Pumped hydro or hydroelectric storage harnesses the potential energy of water at a height and has historically been the most common method of energy storage used worldwide. A pumped hydro system is comprised of two reservoirs at different heights. In periods of low demand and high availability, low-cost electricity is used to transfer water from the lower to the higher reservoir by means of a pump and a turbine or a reversible pump turbine. When electricity is needed, in periods of high demand, water can be released into the lower reservoir, driving the turbine, thereby generating electricity.

With an efficiency ranging from 70 to 85%, it is the most mature and one of the most efficient methods available to store large amounts of energy over a long period of time. Although the required electricity is not instantly available, reaction times are in the order of seconds with installations reaching their full power load in a matter of minutes. The most important downside of pumped hydro storage, however, is that it suffers from geological restrictions: not all locations are suitable as it requires large reservoirs at different heights.

3.3.4 Batteries

A battery consists of one or more electrochemical cells, which store electrical energy in the form of chemical energy and through electrochemical reactions convert that energy into electricity. Each electrochemical cell is made up of two electrodes separated by an electrolyte – a liquid, gel or solid substance. During discharge, this electrolyte enables movement of positively charged ions between the two electrodes, thereby generating a balancing flow of negatively charged electrons through an external circuit connected to the battery. Batteries for energy storage purposes are rechargeable batteries, i.e. the flow of ions and electrons occurs in the opposite direction, charging the battery when it is connected to an external electric source. The battery is charged when any excess power is available and discharged as needed. Several types of batteries exist, depending on the materials used in the electrochemical cells, e.g. lithium-ion, lead-acid, magnesium-ion, nickel-cadmium etc. For storage applications, lithium-ion is still the most common technology available.

Battery storage is highly versatile and scalable and can therefore be used for residential and utility-scale short-duration storage applications in distributed as well as centralised setups, and in both mobile and stationary systems. The fall in the cost of lithium-ion batteries is one of the key drivers of the increased demand for battery storage. According to Bloomberg New Energy Finance prices have dropped by 80% between 2010 and 2017[4], and costs are projected to fall another 52% between 2018 and 2030[5]. Moreover, the rise of electric vehicles has spurred innovation in battery technology. Nevertheless, several challenges remain, e.g. improving energy density, charging capabilities, lifetime and environmental and safety performance. .

[4] Source: Bloomberg New Energy Finance, Lithium-ion Battery Price Survey, 2018

[5] Source: Bloomberg New Energy Finance, Long-term Energy Storage Outlook, 2018

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3.3.5 Vehicle-to-grid

Fully charged and parked electric vehicles are actually large batteries sitting idle. Why not put this storage capacity to better use? This is where vehicle-to-grid (V2G) technology comes into play: when equipped with a bidirectional charger capable of charging and discharging their batteries on demand, these vehicles can act as mobile energy storage units to provide services to the grid by managing their charging patterns according to specific grid requirements.

At the November seminar a study was presented which analyses the conditions for profitability of an investment in a fleet of electric vehicles fitted with bidirectional chargers to provide frequency containment reserves (FCR) to the grid[6]. FCR or primary reserves are fast-acting reserves used for the short-term balancing of supply and demand, which requires the capability to increase or decrease power output at very short notice, typically within 0 to 30 seconds. The authors calculated the net present value (NPV) of the investment for 4 market design scenarios and different fleet sizes. The market design scenarios differed according to temporal granularity (i.e. 1 hour, 4 hours or 1 week; the latter corresponding to the actual temporal granularity of the FCR market) and volume granularity (i.e. 0.1 MW or 1 MW, which is the minimum bid imposed by the market design currently in place). Simulations showed that in order for a charging supplier to have a positive NPV, given the current market design, the fleet should total at least a few thousand vehicles, which would be a tall order for a starting business. A sensitivity analysis further demonstrated that market design parameters have a big impact on the profitability of the investment. It also highlighted that, given the current market design, the minimum fleet size is significantly affected by every other parameter considered (reserves price, recurring costs, lifetime, discount rate etc.). However, in the market design scenario with the highest granularity (i.e. 1 hour and 0.1 MW), the only influencing parameters are average reserves price and recurring costs.

The authors regard this analysis as a mere first step towards building a V2G business model. Indeed, they consider only one actor, i.e. the aggregator managing the fleet, who captures all the value, whereas in reality, there will be several actors fulfilling different roles and the value should be shared among these actors, including the users of the electric vehicles.

The study described here is only one of many in the emerging field of V2G, which is undeniably a hot topic in research. Expectations are running high, with enthusiasts going as far as predicting that V2G is the ultimate energy solution. However, the jury is still out as there are several uncertainties and issues yet to be resolved, which is perfectly normal for an emerging technology.

3.3.6 Power-to-gas

Power-to-gas (P2G) technology enables the storage of excess electricity from renewable resources by converting it to gas. There are different methods, all of which first use electric energy to produce hydrogen (H_2) by water electrolysis. Depending on the method, this H_2 is subsequently combined with CO_2 to convert it to methane (CH_4). H_2 and CH_4 are either injected in the existing gas grid or

[6] Borne, O; Petit, M; Perez, Y. (2018) “Net-Present-Value Analysis for Bidirectional EV Chargers Providing Frequency Containment Reserve”

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stored underground (see also 3.5.3) and then used for electric power generation in gas turbines or gas engine plants or, in the case of H_2, fuel cells.

There are currently few economical alternatives for grid-scale seasonal energy storage, given that pumped hydro suffers from geological restrictions. In countries with a gas network infrastructure, though, large-scale gas storage facilities and P2G technologies may provide alternatives to pumped hydro while complementing battery storage. Researchers from the university of Liège in collaboration with Fluxys, the Belgian gas infrastructure operator, developed a theoretical framework to tackle long-term centralised planning problems of integrated energy systems with bidirectional coupling of the electricity and gas infrastructure [7]. Which energy generation, conversion and storage technologies, and how much of each, should be deployed to supply electricity at minimum costs while satisfying technical constraints and specific policy targets, i.e. carbon emission and electricity import quota? The team modelled a simplified energy system comprising different technologies, i.e. (1) non-renewable generation including combined cycle gas turbines, H_2 fuel cells and other non-renewables (combined heat and power, biomass and waste), (2) renewable generation encompassing onshore and offshore wind turbines and solar PV panels, (3) pumped hydro storage and batteries and (4) the gas system made up of electrolysers, methanators and hydrogen and methane storage.

This framework was then applied to the Belgian energy system in order to identify the cost-optimal energy mix along with short and long-term (seasonal) storage requirements beyond 2025, when no nuclear power plants are assumed to be in operation. Two scenarios were analysed: the first put annual carbon emission quota at the estimated 2018 level and electricity import quota at 10% of annual electricity consumption, while the second used low carbon emission quota, i.e. 33% of 2018 levels, and the same import quota of 10%.

The simulations indicate that P2G, gas storage and batteries become relevant only when ambitious carbon dioxide reduction targets are pursued, in which case they are a necessity. This study also shows that economics alone will not be conducive to the emergence of large-scale P2G infrastructures, but that instead revised carbon pricing mechanisms or carbon quota should be considered.

3.3.7 Compressed air energy storage

Compressed air energy storage (CAES) systems use excess or off-peak electricity to compress ambient air, storing it in underground caverns or storage tanks. When electricity is needed, the pressurised air is recovered from its storage, heated and expanded in an expansion turbine driving a generator, which delivers the electricity back to the grid.

Unless the heat generated during air compression can be recovered and re-used, the efficiency of CAES systems is relatively low, i.e. 40-50%. Higher efficiencies up to 70% can be achieved if this

[7] Berger, M; Radu, D; Fonteneau, R; Ernst, D; Deschuyteneer, T; Detienne, G. (2018) “Centralised Planning of National Integrated Energy System with Power-to-Gas and Gas Storages”

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heat is captured and used to reheat the compressed air in the electricity-generating turbine, in which case no extra gas is needed (third generation CAES technology).

Like pumped hydro and P2G, CAES is suited for seasonal energy storage. There are only two large-scale CAES plants in operation worldwide: a first-generation 290 MW plant in Huntorf, Germany, built in 1978, and a second-generation 110 MW plant in McIntosh, Alabama, US, which was commissioned in 1991, both designed to store inexpensive base load power produced by conventional sources during off-peak periods. Natural gas is burned in the compressed air to power an electricity-generating turbine when electricity is needed. The emergence of intermittent renewables, however, has revived interest in the technology. Current CAES developments focus on third generation CAES technology which aims to avoid the use of fossil fuel.

Not unlike pumped hydro, traditional CAES systems suffer from geological restrictions as they require suitable large underground caverns to store the compressed air. It is therefore all the more interesting that one of the demonstration case studies in the STORY project will experiment with a decentralised, small-sized CAES system, storing the compressed air in above-ground storage tanks. Like batteries, decentralised CAES systems could be installed anywhere (see Box 2).

3.3.8 Thermal energy storage

Thermal energy storage (TES) is a technology that stocks thermal energy by heating or cooling a storage medium so that the stored energy can be used at a later time for heating and cooling applications and power generation (IRENA, 2013). Energy can be stored as heat for later use, or for conversion into electricity. The stored heat can be obtained in different ways: solar thermal heat, electricity conversion into heat, remaining heat from industrial processes, or heat produced by electricity generators.

There are three main kinds of thermal energy storage systems (IRENA, 2013):

1. Heat storage based on storing thermal energy by heating or cooling a liquid or solid storage medium (e.g. Water, sand, molten salts, rocks).
2. Heat storage using latent phase materials, e.g. Changing from a solid state into a liquid state.
3. Thermo-chemical storage using chemical reactions to store and release thermal energy.

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Box 2: Distributed CAES provides local load on demand

Lecale, a semi-rural area in the south-east of Northern Ireland, hosts a small-scale CAES demonstration project aimed at illustrating the benefits and opportunities of providing decentralised electrical storage through compressed air and stored heat to areas with relatively weak existing electrical infrastructure. The project should help to demonstrate the ability to store and regenerate electricity with standardised technology components and will validate models for operating the unit within a residential setting, both to maximise the penetration of local sources of renewable energy and to minimise transmission and distribution network reinforcement requirements. The project is one of six STORY demonstrators and is led by B9 Energy.

The demonstration unit is installed at the 33/11 kV Bishopscourt central substation, which is connected to a large solar PV installation. Two other distributed generators, a tidal turbine and a wind turbine, are connected to the 11-kV network, as are 300 houses and a fish factory. The CAES unit takes electricity from the grid to drive a compressor that stores the compressed air in above-the-ground air storage cylinders. The heat released during compression is recovered and stored in molten salt tanks. When electricity is needed for export, the compressed air is directed through an expander with heat injection from the heat store to drive a generator. The area occupied by the unit is rather compact, about 20 m by 20 m, including the control room, but excluding space for access and parking.

3.4 Alternatives to storage

The growing share of intermittent renewable energy sources in the energy mix increases the flexibility requirements of the grid. Energy storage, as we shall discuss further below, offers many opportunities, however, it is but one way to provide flexibility to the system, in addition to grid extension, flexible conventional generation and demand side management.

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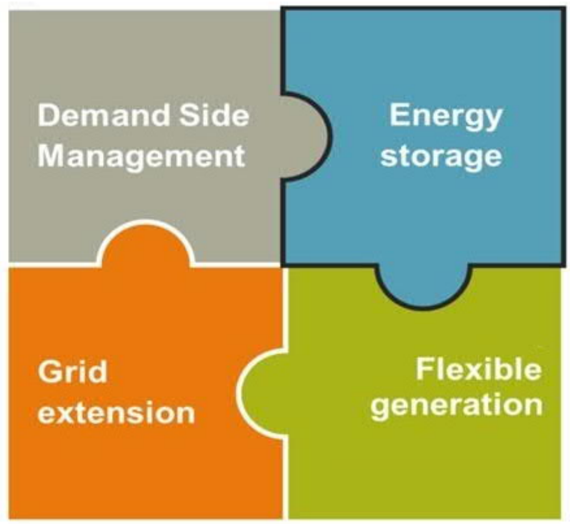

Source: adapted from EASE

Grid extension used to be a straightforward solution, but one requiring significant investments, for which there is little public support in the current social and economic climate. Flexible generation can be provided by both conventional and renewable energy sources. Today, however, flexible power generation still mainly comes from gas turbine plants, and while they are currently being used effectively to provide balancing services, there are concerns about their sustainability. Energy storage, grid extension and flexible conventional generation are all supply-side sources of flexibility, adjusting the amount of electricity provided to the grid to match demand. In contrast, demand-side management is a method of adjusting electricity usage according to availability by having users change their electricity consumption pattern in response to automated signals or incentives provided by the network operator. Demand-side management has been around for quite a while now and although it is designed to relieve and help balance the grid, it has yet to demonstrate its full potential.

Each having their pros and cons, these four solutions are to some extent complementary and the flexibility issue will need to be addressed by a combination of two or more of them. Only time will tell which of the four, if any, will prevail. A lot will depend on the evolution of the costs involved. It is also worth pointing out that different countries have different views on the issue (see section 3.6).

Takeaways

- The increasing share of intermittent renewables also increases the flexibility requirements of the electricity system.
- Energy storage is not limited to batteries. There are several storage technologies available, each with their pros and cons.
- Storage is one of four complementary solutions to increase flexibility in the electricity system.

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3.5 Challenges and opportunities

The business case for energy storage obviously depends on its economic viability. Even so, this is not the only factor to consider. In assessing the potential of energy storage, we should look beyond the cost-benefit analysis. Public opinion, for example, is notoriously crude and unforgiving and can make or break an innovation. Moreover, social and geopolitical motives are equally important drivers for the development and adoption of energy storage solutions. And finally, we should not lose sight of any issues because, as always, there is a flip side to the coin. In this section we discuss Tesla's powerwall proposition for home and industry, possibilities of storage for developing countries, the option to leverage storage as a strategic reserve in developed countries, and the main challenges that storage faces such as raw materials and supply chain, end of life and safety issues.

3.5.1 Public opinion: The Musk factor

On 1 May 2015 Tesla CEO Elon Musk caused quite a stir. His Tesla Energy keynote had editors waxing lyrical, sending social media into overdrive. In what some have labelled a TED-style talk, while others likened it to a Steve Jobs performance, Musk launched the Powerwall and Powerpack batteries for residential and utility use[8]. Yet, rather than selling a product, he was painting a vision of a brave new battery-powered world, promising a fundamental transformation in how energy is delivered across the Earth. And because people do not buy products but solutions, he put his finger on the problem: batteries are riddled with issues. They are still rather expensive, inefficient, unscalable and, not least, unappealing – no one would dream of putting standard batteries in their living room. The Tesla Powerwall showed once and for all that batteries too can be attractive. But is a radical transition to renewable energy feasible? With simple mathematics Musk argued it is: 160 million Powerpacks providing 16,000 GWh are enough to transition the entire electricity production in the US. With 900 million Powerpacks the entire world's electricity generation could be made renewable and primarily
from solar PV panels. Transitioning not only electricity generation but also transport and heating to renewables would require 2 billion Powerpacks. Does this seem excessive? Considering there are almost as many cars and trucks on the road worldwide, Musk for one concluded that 2 billion is not the astronomical amount it sounds.

Feasible or not, one thing is certain: the great merit of inspiring and persuasive presentations like this one is that they manage to win the public support, even enthusiasm, for battery technology. Who knows, perhaps one day a Powerwall will be as desirable as the next iPhone.

[8] https://www.youtube.com/watch?v=NvCIhn7_FXI

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Box 3: FlexGrid uses AI to accelerate universal energy access

FlexGrid is a social enterprise that brings electricity to isolated rural areas in Sub-Saharan Africa where connection to the medium- or high-voltage grid is not yet possible. The FlexGrid solution combines the simplicity of home solar systems with the power of traditional minigrids. Vlerick students helped develop the financial plan to attract investors, which resulted in financial support from the European Commission's Electrification Financing Initiative, ElectriFI.

As simple as home solar systems may be, they lack range and cannot be extended. Traditional minigrids with modules combined and controlled using a master-slave configuration require complex engineering and maintenance and are difficult to scale up. Moreover, if one of its components fails, the system fails. Because neither of these systems is a viable option, FlexGrid developed a radically new approach: a grid with a fully decentralised architecture, enabled by swarm intelligence.

Swarm intelligence is artificial intelligence inspired by a trait found in nature, e.g. in a school of fish, a flock of birds, a colony of ants or a beehive. Individuals in these communities can only perform a limited set of actions, but together they are capable of solving complex problems, efficiently, without there being a central control organism.

A FlexGrid is made up of interconnected power hubs that consist of one or more power units, i.e. portable solar panel powered batteries delivering 230 V AC, fitted with swarm technology developed by award-winning Swiss company Power-Blox. There is no central steering. Each power unit operates independently, while communicating with other power units. If one power unit fails, the others take over. Adding new power units is as easy as playing with Lego: the extra unit is plugged in and the system configures itself, without service interruption. In short: a FlexGrid is an autonomous, self-learning system that requires no engineering, configuration or maintenance and that can be extended endlessly.

The commercial business model is tailored to low-income households: there are no subscription or fixed usage fees and no minimum consumption constraints. Consumers buy credits via their mobile phones, providing them access to the full power of the FlexGrid. This pay-as-you-consume model is ideal as 70-80% of African households cannot afford regular electricity supply. Performance of the grid and consumer demand are monitored 24/7 via the cloud. The biggest advantage by far of a FlexGrid is that, as the name says, it is flexible. As a truly demand-driven system, it makes it possible to start small, with a substantially lower upfront investment, and grow organically, based on demand. This avoids the risks of both overinvestment and underinvestment.

The pilot project was set up in Zantiguila, 60 km south-east of Bamako, Mali, where a FlexGrid made up of 14 power units provides 70 households with a 3.5 kWp solar PV system and 16.8 kWh storage capacity. In the course of 2019 FlexGrids will be installed in 7 villages in Mali, Burkina Faso and Rwanda to supply 400 households with electricity.

Source: www.flex-grid.com

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3.5.2 Developing countries

Autonomous minigrids play an important part in the electrification of rural areas where the electricity infrastructure is non-existent. Minigrids can be located closer to the demand, resulting in lower transmission and distribution costs. Those based on renewable energy sources, such as solar power and wind, have the added advantage of not being dependent on fossil fuel availability. However, for minigrids without a diesel generator as a backup, some form of energy storage is vital to ensure electricity supply security. While economically developed countries can choose from and combine different flexibility solutions (see Box 2), most developing countries do not have this luxury of choice. Their first priority is to increase mere access to electricity in order to enhance socio-economic development.

An inspiring case study illustrating the advantages of a flexible minigrid and the necessity of energy storage technology in developing countries is that of FlexGrid, providing electricity to low-income households and small businesses in Sub-Saharan Africa (see Box 3). This social enterprise has developed an innovative minigrid architecture based on artificial intelligence, combining solar PV panels and batteries. The result is a highly modular system ensuring electricity supply security at a lower upfront investment cost per connected user.

3.5.3 Strategic reserves

Despite their carbon footprint being smaller than that of coal plants, gas plants are frowned upon and considered a technology that should be phased out. Be that as it may, we should be wary of throwing the baby with the bathwater. Indeed, P2G technology has the potential to address the energy flexibility challenges (see 3.3.6) and could make good use of the existing gas infrastructure. The EU currently has more underground storage capacity in place than needed, which puts margins in the gas storage business under pressure. In the September 2018 issue of the OIES Quarterly Gas Review, senior research fellow Thierry Bros argues this underground gas storage should be treated as a strategic opportunity. Storage could significantly contribute to security of supply thus swaying public political opinion.

Considering the major natural gas consuming regions, the EU is frontrunner with underground gas storage facilities covering 26% of its gas demand[9], compared with 18% for the US and Russia and 5% for China. Having been a major net importer of gas for many years, mainly from Russia, Europe has developed a gas infrastructure with more underground storage capacity than the other net importers, the US and China. The combination of surplus EU and Ukrainian storage capacity and surplus Russian export potential could result in the EU becoming a global storage provider for gas, ensuring security of supply to the EU and other countries, especially China. As Bros points out, the main obstacle is the 2009 Council Directive 2009/119/EC, which imposes an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products – an obligation defined at a time when oil was more relevant than it is today. His advice is to rescind the strategic oil storage obligation and replace it with an energy storage obligation allowing all energy sources (oil, gas, water and electricity) and storage technologies to compete on an equal footing.

[9] This number refers to the EU and Ukraine

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Although not a mainstream idea yet, it is one EU commissioners and other EU politicians are very inclined to entertain. With the EU having few natural resources, the political appeal of a strategic energy storage asset is obvious.

3.5.4 Raw materials and supply chain

Most commercial lithium-ion batteries contain cobalt, an increasingly scarce precious metal. Over the past two years, the price of cobalt has quadrupled. As the demand for lithium-ion batteries will continue to increase, battery manufacturers are looking for ways to reduce the cobalt content. Scarcity and price are, however, not the only reason to change tack. Cobalt is primarily mined in the Democratic Republic of Congo, a politically instable country. More importantly, it is mined by children working in dangerous conditions and battery manufacturers no longer want to be associated with child labour.

In May 2018, Panasonic, Tesla's battery cell supplier, announced it is aiming to develop cobalt-free automotive batteries in the near future, having already cut down on cobalt usage. Reducing the cobalt content is first and foremost a technical challenge: lithium iron phosphate, lithium manganese oxide and lithium titanate batteries are cobalt-free, but their energy density is lower than that of lithium nickel manganese cobalt oxide or lithium nickel cobalt aluminium oxide cells. As the saying goes: every challenge comes with opportunities, and this one is no exception. Lithium iron phosphate batteries, for example, are said to be safer, having a cycle life similar to that of lithium nickel manganese cobalt oxide batteries and several manufacturers already offer them for storage applications. Researchers also continue to develop alternatives to lithium-ion battery technology altogether, such as flow batteries. Unlike conventional batteries, flow batteries keep electrodes and electrolytes separate, with energy being stored in electrolyte tanks that can be any size. As a result, flow batteries can store and discharge larger amounts of energy, in a safer and more durable way than their lithium-ion counterparts. Finally, organic flow batteries would even do away with the metal-containing electrolytes. Ongoing research is looking into quinones, organic compounds, as an alternative. The lifetime of these organic batteries is still an issue, though.

3.5.5 End-of-life

Despite considerable effort being put into increasing the longevity of batteries, they do have a finite lifespan. While recycling seems the obvious solution, there are technical and economic limitations that risk undermining its business case.

Recycling is considered beneficial for the environment, but the recycling process is not without problems as the chemicals used in batteries are hazardous, exposing those handling them to significant health and safety risks. Recycling also suffers from diminishing returns as the quality of the extracted materials degrades with every recycling cycle. Moreover, due to battery manufacturers investing in ways to reduce the use of certain raw materials (see above), there are increasingly fewer high-value materials worth extracting. In any case, sooner or later, we must deal with the end-of-life issue. Public opinion so far has turned a blind eye to the West using developing countries as its dumping ground for electronic waste, but for how much longer?

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3.5.6 Safety

Increasingly more household and handheld devices are powered with batteries, which from time to time malfunction. And when they do, they tend to make it to the headlines. The Samsung Galaxy Note 7 is one of the most mediatised cases. Less than a month after its launch in 2016, production was discontinued following a worldwide recall due to several incidents with the phone's battery catching fire. Exploding phone batteries are hardly ever completely out of the news, competing for attention with defective batteries in smart watches, laptops and e-cigarettes. Malfunctioning batteries are not limited to those in handheld devices either. Again in 2016, the US Consumer Product and Safety Commission issued recall notices against several manufacturers and retailers for more than half a million hoverboards after at least 99 incidents had been reported of injuries and material damage due to the battery packs overheating. And every Tesla car battery catching fire, spontaneously or after a car crash, continues to be big news, even if no one was injured.

If safety issues with small to medium-sized batteries are enough to provoke public anxiety, then what about large storage batteries? Incidents with small batteries reflect negatively on the entire battery industry. Moreover, it is not as if there have not been issues yet. In 2012 the 30 MW Kahuku wind farm in Hawaii suffered more than USD 30 million worth of damage when the 15 MW storage battery caught fire. It appears this event is the reason why insurers are still reluctant to cover battery storage assets.

Takeaways

- It is important to create public support for energy storage and storage technologies.
- In developing countries energy storage can mean the difference between electricity and no electricity.
- Gas storage should be treated as a strategic opportunity.
- Issues arousing public concern, even though they are mainly related to battery storage technology, may affect acceptance of storage technology in general.

3.6 The impact of regulation on the business case for storage

Technologies and business models do not exist in a vacuum. Regulation in particular is known to shape their development. Ranging from market design and tariffs to fiscal stimuli and subsidies, each form of regulation has a different impact on the business case for storage. Regulation affects the business case when it defines what market products storage has access to, what tariffs storage owners face, and what support incentives are available to investors.

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3.6.1 Market design

Energy storage cannot be reduced to a single technology or application. Between pumped hydro storage, prototypical of long-duration storage and fast-acting batteries there is an entire range of technologies with different properties and characteristics rendering energy storage extremely versatile. Not only is it essential in the integration of intermittent renewables and conventional energy sources, it can play a role in any energy market – the wholesale and the balancing markets, as well as proving services to both the transmission and the distribution grid to ensure efficient, stable and reliable grid operation (e.g. transmission and distribution investment deferral, voltage control, congestion relief, black start capacity etc.). A case in point is the demonstration project undertaken by UK Power Networks near the town of Leighton Buzzard in South East England, where a multi-purpose grid-connected battery storage system performed peak-shaving services as and when required, while any remaining capacity could be used for other grid services (see Box 4).

While in principle energy storage devices can provide different services across all levels of the energy system, market design is such that there are several unintended barriers to their deployment. Technical access requirements for regulated markets are not yet adapted to the current context, but stem from a time when there were clearly distinguished roles, i.e. (1) generation, (2) transmission and distribution and (3) consumption. Energy storage devices do not fall into a single category, acting as both generators and consumers. Grid connection requirements, for example, also fail to take into account the presence of energy storage, with the exception of the long-standing pumped hydro installations. This is apparent in product definitions imposing minimum bid sizes and contracting periods that are out of reach for battery systems.

Researchers from TU Delft University and the Austrian Institute of Technology developed a detailed assessment framework mapping the barriers to entry of distributed energy sources, including storage, in the balancing market[10] while comparing the situations in Austria, Germany and the Netherlands. Based on their analysis they proposed a stepwise approach to adapting the balancing market design in order to enable storage technologies to compete on a level playing field against other flexibility providers. First of all, formal access requirements excluding distributed energy sources from participation should be removed. Flexible pooling conditions and separate capacity and energy markets need to be addressed next as they have an impact on most other variables. Extended pooling options, for example, help to reach the required minimum bid size and to comply with longer contracting periods, while splitting balancing capacity and balancing energy markets is necessary in order to be able to reduce bidding frequency – auction configuration variables which, once adapted, will increase competition between different service providers.

The extent to which energy storage can participate in the different markets and services depends on the regulatory framework, in which market design and tariffs (see 3.6.2) play an equally important part. For the business case to be robust, any regulatory framework should enable revenue stacking, i.e. energy storage providers should be allowed to tap into all possible sources of income, providing a combination of services in order to maximise the value of their storage facility.

[10] Poplavskaya, K; de Vries, L. (2018) “Impact of balancing market design on business case for storage”

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Such multiple service business models require a regulatory framework in which an entity can engage in both regulated and non-regulated activities.

Moreover, grid fees and tariffs should take into account the value provided by energy storage. Short-duration technologies, such as batteries, can respond to frequency imbalances in a matter of milliseconds, but have a limited service time compared to long-duration technologies, such as pumped hydro and P2G, which can be used to address weekly, monthly and seasonal imbalances. Each technology has its merits and strengths and their remuneration should reflect the value provided to the system. Unfortunately, at EU level, the value of some technologies' exceptionally fast reaction time is not yet recognised, and fast-acting energy storage devices are remunerated at the same rates as slower-reacting ones. This is not the case in the US, where already in 2011, the US Federal Energy Regulation Commission issued order 755 on frequency regulation compensation in the organized wholesale power markets, which requires system operators to add a performance payment with an accuracy adjustment to the capacity payment typically used in markets for ancillary services. In 2016 it issued order 825 on settlement intervals and shortage pricing, requiring that each regional transmission organisation and independent system operator align settlement and dispatch intervals[11] and trigger shortage pricing for any interval in which a shortage of energy or operating
reserves is indicated during the pricing of resources for that interval. These pay-for-performance schemes are aimed at providing appropriate incentives for resource performance, encouraging fast responding units to participate in frequency regulation.

While this may all sound straightforward, the energy storage sector is well aware of the challenges: in a fast-changing technological context it has become increasingly difficult to develop policy and regulation. However, precisely because it is almost impossible to predict and anticipate technological developments, it is all the more important to ensure that the new EU network codes[12], for example, do not introduce any additional barriers to entry in any of the regulated markets, i.e. the wholesale, the balancing and the ancillary services markets. However legitimate and understandable this demand for investment certainty may be, it remains to be seen if and how it could be satisfied without compromising the level playing field.

[11] Order 825 requires that each regional transmission organisation and independent system operator align settlement and dispatch intervals by: (1) settling energy transactions in its real-time markets at the same time interval it dispatches energy; (2) settling operating reserves transactions in its real-time markets at the same time interval it prices operating reserves; and (3) settling intertie transactions in the same time interval it schedules intertie transactions.
[12] Rules governing grid connections, markets and system operation, designed to provide a sustainable, secure and competitive electricity market across the EU.

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Box 4: The SNS project defers grid reinforcement while making the business case for revenue stacking

The Smarter Network Storage (SNS) project was a pioneering demonstration project to analyse how grid scale battery storage could be used as an alternative to distribution network reinforcement while also being used for a range of other services in different business models. Running from 2013 to 2016 it was largely funded by Ofgem's Low Carbon Network Fund. Additional funding was provided by UK Power Networks and other project partners.

The primary substation near Leighton Buzzard, in South East England, was chosen as the site for this project. At times, peak demands at the substation exceeded the installed capacity. The conventional solution would be to install additional capacity. While solving the constraint, a reinforcement project would have a lead time of up to 4 years and the installed capacity would remain mainly underutilised until demand caught up with supply. A 6 MW/10 MWh battery storage system was designed to provide peak shaving for 1.5 hours to provide appropriate network support during the forecasted winter peaks. The system was built, operated and maintained by UK Power Networks, who also owned the facility. Construction was completed in 12 months, with the site being commissioned in December 2014, 2 years earlier than would have been the case for network reinforcement.

A storage scheduling and dispatch optimiser system was developed and tested to enable the use of the battery facility for other services during off-peak periods, which would help monetise the value of the facility over and above what peak shaving services could provide. Based on historic customer electricity demand, scheduled network outages etcetera, this system determines the optimised scheduling and dispatch of the storage facility, with priority given to network security, i.e. the schedule ensures that the storage system is available to support the local network by providing peak shaving when required, while for the remaining time it provides the most profitable services. Subsequently, UK Power Networks trialled various other services that could be provided, not only to evaluate their feasibility, but also to demonstrate how revenue from multiple services could be stacked to achieve the optimum business case. In addition to providing peak shaving services, the facility experimented with ancillary services, such as reactive power support, voltage control, frequency response, short-term operating reserve, TRIAD support and capacity market participation. They also simulated different business and ownership models.

The project delivered on all accounts, performing peak shaving services as intended while successfully deferring grid reinforcement. The trials showed that SNS could technically deliver all of the tested services individually and some simultaneously through the concurrent use of active and reactive power, e.g. reactive power support and frequency response services, which require active power. It also showed that revenues from peak shaving alone were insufficient and that a viable business case would rely on various ancillary services. At the time of the project, frequency response provided the highest revenue.

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3.6.2 Tariffs

Consumer electricity bills in capital cities across the EU broadly consist of (1) energy costs, (2) network charges, (3) charges for renewable energy sources (RES charges) and (4) other taxes and charges and VAT. In 2017 energy costs represented on average 35% of the bill; this portion has been steadily decreasing since 2012, when it was 41%. By contrast, the share of RES charges has more than doubled from 6% in 2012 to 14% in 2017. The portion of network charges during the same period remained relatively stable at 27%, mostly distribution grid charges[13].

These grid charges or grid tariffs are designed to recover grid operating costs, i.e. running costs and investments. Historically, DSOs in many countries, including Belgium, apply volumetric tariffs or fees based on the amount of electricity drawn from the grid. Although big consumers do not necessarily cause more costs, volumetric distribution network tariffs were considered adequate enough and, equally important, perceived to be fair – the more affluent consumers who are likely to use more electricity, paying higher network contributions. With the uptake of solar PV panels this logic no longer held true. The use of volumetric distribution network charges with net metering resulted in solar PV panel owners paying significantly less than consumers who could not afford to invest in solar panels, all the while continuing to rely on the grid. All of a sudden, volumetric tariffs no longer seemed fair, which triggered the debate about how to change distribution network charges.

A temptingly simple approach is to charge for peak consumption. Solar panels generate most energy during the day, while their owners, like all other retail consumers, tend to use most of their electricity in the evenings, i.e. their peak consumption has not really changed. Moreover, this peak consumption is one of the most important drivers of network costs as the grid size is determined by system peak demand. This solution, as easy as it may seem, is not flawless: individual peak consumption does not necessarily coincide with system peak usage and tariffs therefore would need to send different signals at different locations and times.

In today's energy landscape with solar PV panels and batteries, it is crucial to bear in mind that grid tariffs can have unintended adverse effects on an individual consumer's investment decisions and, by extension, on the business case for home battery storage. Volumetric distribution network charges with net metering provide no incentive whatsoever for solar panel owners to invest in batteries as the grid acts as a free battery they can use at their own discretion. They can inject their excess power into the grid, free of charge, draw electricity when needed and pay only for their net consumption, if any. Conversely, grid tariffs based on peak consumption may over incentivise solar panel owners to invest in home batteries in order to avoid network charges. Moreover, in both scenarios the grid costs are being passed on to consumers without solar panels and/or batteries.

Obviously, grid tariffs not only have an impact on the business case for storage in a consumer context, they are also relevant on an industrial scale. As a study by EASE showed[14], grid tariffs

[13] Source: ACER/CEER - Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 - Electricity and Gas Retail Markets Volume
[14] Source: EASE Position on Energy Storage Deployment Hampered by Grid Charges, 2017

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imposed on utility-scale energy storage systems like pumped hydro vary significantly across EU Member States. As a result, investment in pumped hydro storage is most likely driven by tariff considerations rather than by geological or topographical suitability and local needs. A harmonisation of grid fees would ensure a fairer competition between storage providers.

3.6.3 Support Incentives

Most of the energy storage technologies discussed in this paper are still emerging or developing and therefore not yet economically viable, which means they could benefit from some form of regulatory support. Regulatory support being a highly political choice, it is expected to differ across the world.

If the EU’s ambitious target of 32% renewables by 2030 is to be met, our energy system will have to tap into much-needed sources of flexibility. Determined to leave all the options open, the EU does not want to favour one source of flexibility over the other - energy storage, grid extension, flexible conventional generation and demand side management. Nevertheless, what is clear is that energy storage will be an indispensable part of the mix to ensure the effective integration of intermittent renewable energy sources while maintain grid stability. For energy storage to play any role at all, be it in the wholesale, the balancing, or the ancillary services market, it is therefore essential that barriers to entry should be removed. However, although market design changes may help to overcome certain obstacles, they are not enough to make the business case viable. Similarly, appropriate tariffs are a sine qua non, but not sufficient as such.

While the EU has subsidised renewables to achieve certain targets, it is not inclined to do the same for storage. Subsidies have enabled renewable technologies to grow and achieve economies of scale, resulting in solar and wind energy becoming cheaper. As far as energy storage is concerned, the EU seems to be banking on R&D support programmes, hoping innovation alone will help to further reduce the costs of storage technologies.

The US has taken a different stance. Rather than wait for the costs of storage to drop in order to achieve economies of scale, it has set targets for energy storage, granting subsidies to support those targets, similarly to its policy on renewables. Admittedly, there is no federal policy yet, but several states have already imposed energy storage deployment targets and in others target processes are underway. Moreover, the US Federal Energy Regulation Commission has a track record of issuing orders in favour of energy storage (see also 3.6.2), the most recent one being order 841, issued in February 2018, which commands to create participation models for energy storage across the country in order to remove barriers to participation of electric storage resources in the capacity, energy and ancillary services markets operated by regional transmission organisations and independent system operators.

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Takeaways

- The extent to which energy storage can participate in the different markets and services depends on the regulatory framework in which market design and tariffs play an equally important part.
- While the EU has set ambitious targets for renewable energy it is also a strong proponent of the idea that grid flexibility can and should be achieved in various ways, considering energy storage to be but one of several possible solutions. Contrary to the US it has not yet set out a clear vision on energy storage with regards to market design and policy support.

3.7 My take

'Energy storage is increasingly recognised as one of the essential technologies that will enable the transition to a decarbonised energy system. We need to work hard now to get the regulatory framework for storage just right – otherwise we risk missing out on the enormous potential of energy storage.'
I - Patrick Clerens, Secretary General, EASE

"Individual residential batteries are seldom the way to go. Issues with safety, in-house emissions as well as safety aspects for firefighters, are to be taken serious: battery technology, but just as well the effective installation and coupling need more attention. Leveraging the storage capacity to a neighbourhood level has several advantages, overall smaller storage capacity compared to individual assets, potential for power quality improvements at a larger scale and the easier and less expensive inclusion for aggregation are just a few. Furthermore, tackling interoperability for 1 device is less effort compared to doing it for a number of individual and tailor-made set ups.
While safety and availability pose one challenge, an important aspect to be taken into account is information provision in a way that is understandable for the different stakeholders, e.g. permitting bodies are not used to terminology as power quality, energy markets, phase balancing and curtailment. We will only enable a roll out of storage at large if we manage to communicate in a multitude of languages."

- Leen Peeters, STORY Technical Coordinator, Think- E

"New regulatory framework is necessary for the effective roll-out of storages, but it needs to be carefully designed, to not lead to unintended effects on the market."

- Mia Ala-Juusela, STORY Project Coordinator, VTT

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3.8 Further Reading

The following papers were presented at the November seminar:

Berger, M; Radu, D; Fonteneau, R; Ernst, D; Deschuyteneer, T; Detienne, G. (2018) "Centralised Planning of National Integrated Energy System with Power-to-Gas and Gas Storages"

Borne, O; Petit, M; Perez, Y. (2018) "Net-Present-Value Analysis for Bidirectional EV Chargers Providing Frequency Containment Reserve"

Govaerts, N; Bruninx, K; Le Cadre, H; Meeus, L; Delarue, E.(2018) "Spillover Effects of Distribution Grid Tariffs in the Internal Electricity Market: an Argument for Harmonization?"

Poplavskaya, K; de Vries, L. (2018) "Impact of balancing market design on business case for storage"

Schillemans, A; De Vivero Serrano, G; Bruninx, K. (2018) "Strategic Participation of Merchant Energy Storage in Joint Energy-Reserve and Balancing Markets"

Schittekatte, T. (2018) "On the interaction between distribution network tariff design and the business case for storage"

IRENA, IEA-ETSAP (2013) "Thermal Energy Storage, Technology Brief".

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4 Summary of STORY Project Recommendations on Regulation and Business Models

The STORY project has identified five main areas of discussion regarding business models and regulation for storage: legal definition of storage, network tariffs, DSO participation in storage projects, market design, and business model enablers. A first description of main regulatory topics was presented by Vlerick in a webinar in May 2019[15]. The main regulatory discussions were debated internally with demo leaders and STORY project participants during a General Meeting in April 2019 and in October 2019. An iterative process with the project participants was then carried out to identify the main issues affecting the STORY project demos. The issues identified were then narrowed down and discussed during a one-day meeting in Leuven Belgium in January 2020.

The five topics mentioned above are summarized in this chapter. For background information and motivation behind each recommendations please see the Annex 8 'Policy Brief on Recommendations' .

4.1 Recommendations on the Legal Definition of Storage

The legal definition of storage affects whether an asset is considered as a consumption or generation unit connected to the network. This point is recognized in the Commission staff working document 2017-61 which states that: "The lack of a clear definition for energy storage in the regulatory framework resulted in a lack of coherence in the classification of storage facilities into generation and/or consumption across Member States" (European Comission, 2017).

The legal definition of storage that can be found in legislation so far, defines the role of storage in the system, broadly speaking, as a system to defer the use of energy over time. However, it fails to define whether to consider storage as generation or as consumption. This has implications on the tariffs for use of the network, the levies and fees, and the obligations of the storage asset management.

The STORY project advocates for the harmonization of the legal definitions of storage used by the TSO, DSO, market design platforms and participating actors. The energy package proposes a legal definition of the act of storing energy which can constitute a first step in this direction. However, we consider it could be extended by:

- Distinguishing between storage assets set behind the meter and storage assets directly connected to transmission or distribution assets as otherwise, directly connected assets run the risk of incurring grid double charges as will be discussed below.
- Including heat and gas storage, as well as their interaction with the electricity network as currently only electrical storage is considered in the regulation.
- Distinguishing in the grid connection codes between permanent versus mobile storage units.

[15] A recording of the webinar is available here: http://horizon2020-story.eu/webinar-on-regulation-for-storage/

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4.2 Recommendations on Network Tariffs

The STORY project recommends that tariffs design should aim for grid cost recovery, technology neutrality, and separation of energy destined for storage vs final consumption. Each item is discussed next.

- Grid cost recovery: Grid cost recovery means that grid charges should adequately recover the grid costs incurred by network operators. Capacity-based network tariffs incentivise consumers to lower their individual peak demand. The two other network tariff designs, volumetric net-purchase and volumetric bi-directional, result in a difference between the value of on-site generated electricity that is self-consumed and electricity that is directly injected back into the network. There is a trade-off between cost reflectivity and complexity. Detailed cost reflectivity implies more complexity, while tariffs that are too simple may not give adequate incentives. Spreading the grid costs over capacity-based charges, volumetric charges and fixed charges can help mitigate possible distortions.
- Tariff design should be technology neutral as tariffs should aim to legislate for service provision or consumer behaviour in general. A first step in this direction is, for example, the Spanish approach, which regulates self-consumption (including storage) rather than specific technologies.
- For storage facilities directly connected to the network, legislation should make a distinction between energy stored for service provision and energy destined for final consumption. It is the view of the STORY project that energy stored for service provision should not pay the taxes and levies imposed on energy destined for final consumption.

4.3 Recommendations on DSO Participation in Storage Projects

The STORY project proposes three main recommendations: storage assets should be operated by commercial actors, the DSO should have procedures to integrate the operation of these assets and the DSO should follow a balanced process when choosing between network reinforcements and new storage solutions.

- Storage assets should be owned and operated by commercial actors. The storage market is yet immature and commercial parties should be able to valorise their assets by offering services where they add the most value. This may be for internal electricity savings, or for service provision to a DSO, TSO or another market actor who may need it. Storage ownership and operation by a DSO could distort competition thus limiting the possible revenues that market parties may earn. It is important to make a difference between ownership an operation. Ownership of storage by a DSO should be an exceptional situation, where commercially owned storage is not available, but operation could be possible under service agreements. Under normal circumstances, appropriate channels should be enabled, to allow the DSO to contract flexibility services and send signals to a storage owner when needed. Allowing DSOs to exceptionally operate a storage system as part of their network assets could serve two purposes:

  1/ DSOs who have had experience operating a pilot storage project will be able to provide a better service as network facilitators for commercial projects. This will avoid large time delays that a small company may not be able to accommodate.

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Figure 1: Business Model Archetypes in the STORY project

2/ A DSO can learn and define what services can be expected from a battery to create appropriate service tenders.

- DSOs should have procedures that enable the efficient connection and servicing of a new storage facility into the network. For example, the lack of standard procedures in the STORY Oud-Heverlee demo has caused significant time delays in the deployment of the neighbourhood battery. In this demo, the DSO was not involved in the STORY project. In contrast, in the Suha Demo, the DSO was fully involved in the connection and setup of the battery. Even in that case several issues had to be solved on a day to day basis to get the battery to be operational, and once operational to be able to run it smoothly. Elektro Gorejnska and ABB, the technology provider, had nearly daily exchanges of information during several months for troubleshooting. As a result, the DSO should evaluate the grid impact of the local battery energy solution and control.
- DSOs must study the value of using flexibility versus network reinforcement. Only then will they be able to draft clear service definitions up for tender. Flexibility is an instrument that will allow network operators to connect more decentralised production, and eventually electric vehicles, into the network while maximizing the use of the existing infrastructure. It is a challenge to correctly compare the value of flexibility versus physical grid reinforcements. Methodologies to calculate the value of flexibility, and thus the services that a DSO will tender for, are necessary.

4.4 Recommendations on Market Design

The STORY project proposes two main recommendations for market design: technology neutrality in service design and assurance that consumers are enabled to valorise flexibility.

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- Technology neutrality: The STORY project considers that technology-specific products can distort the market towards a specific solution. This distortion could mean that new technology cannot compete/be adopted as they cannot participate on a level playing field. Grid operators should strive to make specific service definitions in terms of time granularity, bid size, and location in the case of distribution grids. Storage is a technology that can enable consumers to offer flexibility services, and ought to be considered within the wider scope of flexibility procurement by system operators.
- The business case for storage facilities largely depends on being able to stack revenues. Storage asset owners that can provide flexibility to the network should be able to valorise their contribution. A retailer can remunerate, or rebate, a consumer's electricity bill when electricity is injected into the network; following the example set by the self-consumption regulation in Spain. An aggregator can pool and valorise the final consumer's flexibility in the electricity markets where they are most valued (balancing, DSO services, etc…). Smart meters that enable remote monitoring and control of loads are essential to enable prosumer participation into markets. Fair management of data from smart meters is similarly relevant. To create a level playing field for aggregators the relationship between third party aggregators and balancing responsible parties needs to be clarified in terms of information confidentiality and transfer of energy payments between both parties need to be harmonized across different markets.

4.5 Recommendations on Business Models

A mapping of the business models in the STORY demo was carried out through a series of three workshops during 2018 involving the demo leaders and other project participants[16]. Figure 1 presents a mapping of the demos comparing the value they create and the level of aggregation of the resources. Participation in different markets is related to project size and aggregation of resources.

The STORY project has three main business model recommendations related to revenue stacking, service aggregation and clear product definition.

- First, the business model for storage depends largely on being able to stack revenue streams coming from either, energy savings, services to system operators or services to other market parties. The potential of a specific project are defined by its technical characteristics. Energy savings can be maximised when a consumer is exposed to varying market prices, both on the energy and grid tariff component. Larger storage facilities have the potential to offer services to system operators directly. Smaller household consumers are currently facing limitations due to the need to comply with market metering and participation requirements. The STORY

[16] The three internal workshops mentioned consisted of defining the business model canvas for each demo within the project, representatives or STORY H2020 partners were present at each session, including an aggregator, demo leaders and technology providers. Two workshops took place during the story general meetings in April and October 2018; while the third workshop took place in Brussels in November 2018. In addition, an advisory board workshop was held in Slovenia in October 2018, it consisted of 14 professionals in the energy sector invited to provide their opinion on business models for storage, and related technologies.

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project has proven that storage assets have the potential to offer services to both distribution and transmission system operators.

- Second, the aggregation of resources is key to enable the value of the flexibility that can be provided by residential consumers. Consumers now can also sell energy and flexibility though at a much lower scale than conventional generation. However, they find that the mechanisms to do so are not available and, as a result, the potential flexibility from smaller consumers is not being reaped. Storage project developers find difficulties in securing long term revenue streams. Energy communities and individual household consumers who have a flexibility potential need to partner with intermediaries who have access to markets. Similarly, smart meter availability is key to reap flexibility from final consumers.
- Third, clear product definition, especially from the DSO perspective is necessary to enable a business case for smaller local flexibility providers. Flexibility services offer value for society when their use would defer grid investment. DSOs need to define technology neutral service tenders that enable prosumers or their intermediaries to valorise their flexibility. More study is needed from the point of view of the DSO to evaluate when and under what conditions flexibility is a better option than grid investment.

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ANNEXES

1 Annex 1: STORY demos perspective on storage business models and regulation

1.1 Introduction

This chapter presents a summary of business models identified for the STORY demos, and the European regulatory framework related to them. The business models for the STORY demos were defined in cooperation with the demo leaders and the STORY partners during three internal project workshops held during 2018. Input was also provided during seminar organized for academia and industry in cooperation with the European Association for Storage of Energy (EASE) in November 2018. The regulatory framework discussion is structured following the findings for the identified business model value propositions discussed during the advisory board meeting in 2018. First, the STORY demo business models are presented and second, regulatory considerations at European level are described.

1.2 The STORY Demos: Business Model Description

A business model describes how a company plans to create value for its customers and capture a portion of the value it creates (Chesbrough & Rosenbloom, 2002; Osterwalder, Pigneur, Clark, & Smith, 2010; Zott, Amit, & Massa, 2011). Nine basic building blocks of a business model are identified: customer segments, value propositions, channels, customer relationships, revenue streams, key resources, key activities, key partnerships and cost structure (Osterwalder et al., 2010). For simplicity, in this analysis three of these building blocks are used: value proposition, customer segments, and key partners. Due to the characteristics of energy markets storage projects have different possibilities to access markets, therefore project size, or aggregation of storage assets is contrasted to the value that storage creates for the different customer segments. A mapping of the business models in the STORY demo was carried out through a series of three workshops during 2018 involving the demo leaders and other project participants[17]. Figure 2 presents a map of the demos comparing the value they create and the level of aggregation of the resources. The main value categories identified are savings for the owner, services to the DSO & TSO and market arbitrage.

[17] The three internal workshops mentioned consisted of defining the business model canvas for each demo within the project, representatives or STORY H2020 partners were present at each session, including an aggregator, demo leaders and technology providers. Two workshops took place during the story general meetings in April and October 2018; while the third workshop took place in Brussels in November 2018. In addition, an advisory board workshop was held in Slovenia in October 2018, it consisted of 14 professionals in the energy sector invited to provide their opinion on business models for storage, and related technologies.

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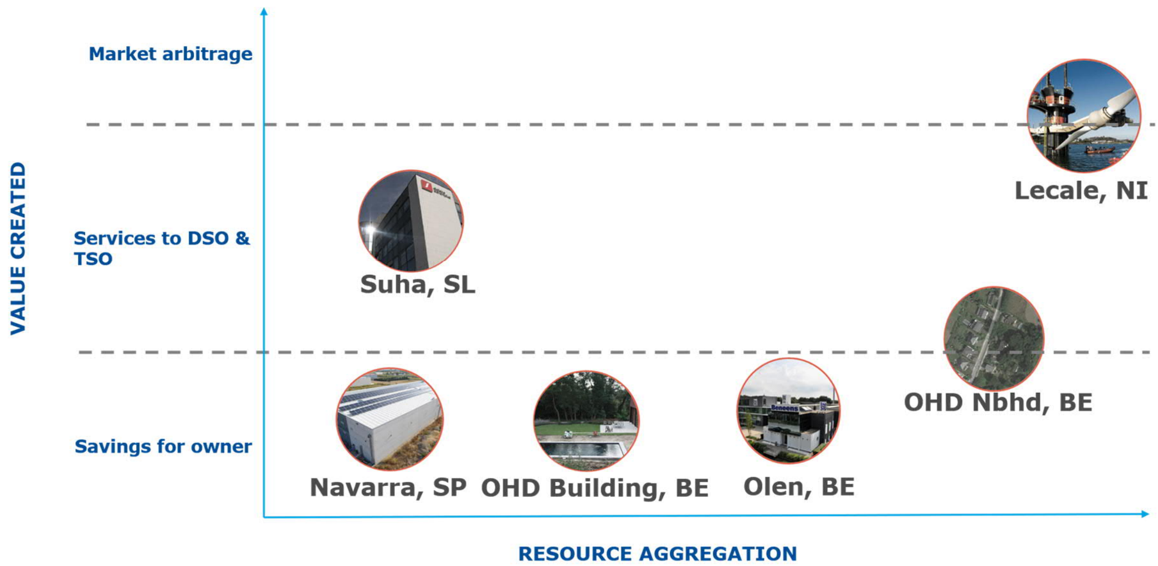

Figure 2: Business Model Archetypes in the STORY project

Savings for the owner are achieved when storage technologies enable an in-house optimization by storing renewable energy when available, or storing energy from the grid at specific times of the day when it is cheaper. The saved energy is then used at an optimal time when energy provided by the grid is more expensive. In the STORY project the Navarra, OHD Building, Olen and OHD Neighbourhood (OHD Nbhd) demos all include systems that enable in-house optimization in order to decrease the energy bill.

Services to DSO & TSO refer to either reserve energy that can be provided for balancing the network, or services for voltage stability and power quality. Balancing services are specifically FCR, aFRR, and mFRR, also known as primary, secondary, and tertiary reserves traditionally procured by TSOs. It has been shown in STORY that the OHD Nbhd, Suha and Lecale demos can provide value for the DSO. They can offer power quality support for the local grid. However, it is not possible to monetize this value in every case. In the OHD Nbhd case, the acting DSO has not defined products for power quality that would receive a remuneration. In the Suha case, the DSO itself is steering the battery and can measure power quality improvements which can contribute to grid investment deferral. The Lecale case can provide services for both the DSO (congestion management) and the TSO (balancing energy).

Market arbitrage refers to trading energy in the day-ahead and real time spot markets in order to help market players balance their portfolios. Market arbitrage with a storage unit consists of buying energy at a time when it is cheap and storing it to sell later at a time when it is more expensive. There are three possibilities in market arbitrage: Day ahead optimisation, intraday optimisation and imbalance optimisation. The latter is used quite often. Whenever there is an imbalance between

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CANVAS BUILDING BLOCK	DESCRIPTION
VALUE PROPOSITION	The bundle of products and services that create value for a specific customer segment.
REVENUE STREAMS	The cash a company generates from each customer segment.
CUSTOMER SEGMENTS	The different groups of people or organizations an enterprise aims to reach and serve.
KEY PARTNERSHIPS	The network of suppliers and partners that make the business model work.

Table 1: Description of selected Canvas building blocks. Based on (Osterwalder et al., 2010)

injection into the grid and offtake from the grid the TSO will need to take balancing actions which will in turn lead to an imbalance price. This price is linked to the most expensive flexibility which the TSO had to use in order to restore the equilibrium. Market parties who are long will receive this price (which can be negative!), market parties being short will need to pay this price. There are many algorithms (including AI/machine learning) that aim predict this imbalance price and who anticipate a decrease/increase in the imbalance price by changing their grid offtake or injection. Theoretically these prices can reach more than 10.000€/MWh which is more than 250times the average yearly power price. The Lecale demo will work with an aggregator in order to participate in the electricity market in Northern Ireland.

This section describes key aspects of each business model for the different demos in the STORY project. Selected building blocks of the business model canvas methodology are presented in the sections that follow. Table 1 presents a summary of the business model canvas items that are presented next for each demo. The value proposition of a company is an aggregation, or bundle, of benefits that a company offers customers (Osterwalder et al., 2010). The revenue model, or value capture, reflects the value that each customer is truly willing to pay for. Customer segments are the different groups of people or organizations an enterprise aims to reach and serve. Key partnerships refer to the network of suppliers and partners of a company. For each demo, customer segments are linked directly to value propositions for each party. Revenue streams reflect the values that can be directly monetized. Key partners reflect the necessary stakeholders that are critical for the operation of the demo.

1.2.1 Case 1: Residential smart home management – Oud Heverlee, Belgium

This demonstration features 13 houses in Oud-Heverlee which together form a microgrid at the end of a distribution line. The aim is to demonstrate the synergy of a neighbourhood strategy for flexibility and grid balancing. In order to accomplish this, everything in the neighbourhood that can store energy needs to be monitored. This ranges from the temperatures of heat storages and buildings to the state of charge of a battery. Furthermore, a centralized system needs to be able to control all the flexible devices that can shift their electricity consumption. Through the LoRa network, Actility, the aggregator involved, provides a simple solution to monitor and control all these different devices. LoRa is a long range low power network to which sensors can immediately connect and start sending data or receiving control signals.

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The residential buildings are located in a single street in Oud-Heverlee, Belgium. They are located at the end of the feeder, facing the typical challenges of power quality in terms of interrupted supply and voltage profile. The zone consists of a mix of old and new houses, has 20 kW photovoltaic energy generation, hybrid PV and vacuum solar thermal energy, air to water and geothermal heat pumps as well as electric cars (STORY H2020 Project, 2018a).

1.2.1.1 Customer segments and value propositions

Value for Residential customers (13 households)

Technology and communications installation: the customers in the demonstration project were connected to smart meters. Certain appliances, such as heat pumps, PV panels and batteries, were connected to automated controllers. A system to observe, measure and control energy use in all houses was installed.

Smart energy management: consumers are helped by the aggregator to better manage their energy consumption. Their use of energy is scheduled to minimize their energy sourcing costs.

Consumer empowerment: increase awareness about energy use of consumers.

Value for the distribution grid operator: Minimize grid exchange- Adjust the consumption to minimize the impact on the grid to improve power quality and minimize necessary network investment.

1.2.1.2 Revenue streams

It is not possible to monetize all the value propositions created in this demonstration. For example, it is shown that the project improves power quality and minimizes network investment in the future. At this moment, however, the distribution system operator does not procure congestion services or provide different types of connection contracts. These topics are currently under debate in the Belgian regulatory sphere.

Technology value for customers: the customers gain the value of the technology and communication devices installed in their premises.

Savings for smart energy management: optimization of customer's energy use can lead to a decrease in their yearly energy bill.

Monthly subscription fee can be paid by the consumer for the smart energy management service.

1.2.1.3 Key partners

Local energy community manager: the community is managed by Think-E, an energy services and consulting company. Think-E manages the relationship with consumers, in terms of signing in to the project, information sessions, and troubleshooting.

Technology providers: Actility and ABB installed smart meters, and LoRa communication technologies. Actility receives the information and developed a controller to enable smart home management.

Distribution grid operator: Fluvius, the local grid operator, is not officially part of the STORY project, though they are aware of it. The smart meters installed are compliant with their requirements. All

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other installations have been done behind the meter. A the moment of the writing of this report the grid operator was not paying for the improvement in power quality that resulted from the pilot.
Household owners: household owners agreed to participate in the project, and opened their homes to teams installing and troubleshooting technology. Their expectations are to upgrade their home technology and obtain savings on their energy bills.
Retailer: household participants already held contracts for energy supply through a retailer before the demonstration began. These contracts continue in operation throughout the demonstration. Almost all of them, except one, pay day and night tariffs. Their retailers are not part of the demonstration and consumers continue to pay their bills as they did before.

1.2.2 Case 2: Battery in industrial zone Exkal

A lithium-ion battery was installed in addition to the previously installed PV plant in Exkal's facility in Navarra, Spain. The battery has a capacity of 50 kW, 200 kWh. According to the previous Spanish regulation it was not possible to feed excess electricity into the grid, which posed a problem during weekends when the factory was not operating. It was also not allowed to charge the battery from the grid. This changed with a new regulation in 2018 and thereby provided options to improve the business case by feeding excess electricity to the grid and charging the battery in off-peak hours.

1.2.2.1 Customer segments and value propositions

Exkal as a customer: the objective is to increase the self-consumption of the energy generated by the PV installation as no interaction with the grid was allowed. This reduced net grid-offtake allows the site to save on grid fees and other taxes. The main value gain is the optimization of the use of the PV plant in combination with the battery in order to cover the electricity demand of the plant and to enable peak shaving. No sales of energy to the network are foreseen.

1.2.2.2 Revenue stream

In use case 1 excess electricity is fed into the grid for market price. In use case 2 the battery can furthermore also be charged from the grid. For the PV 1150€/kWp and for the battery 500 €/kWh were assumed. For the O&M costs for the total set-up 1% of the total installation costs were used. A WACC of 5% was chosen.

Savings in the energy bill: through the use of the PV panels and the battery Exkal saves about €1300 per month in their electricity bill.

	UC 1 -PV only	Use case 2	Use case 3
IRR	11,7%	4,8%	4,6%
NPV	86.546 €	-4.189€	-7.272€

Table 2: Business case EXKAL

The graph below visualizes that if the battery system costs fall to 480Euro/KWh for Use case 2 and 466€ for Use case 3 the NPV would become positive. This illustrates that for this demo with a viable business case can be expected due to falling battery system costs in the next years. Figure 4 shows how a change in the WACC would influence the storage costs to the point of a positive NPV. The battery alone does not provide a feasible business case.

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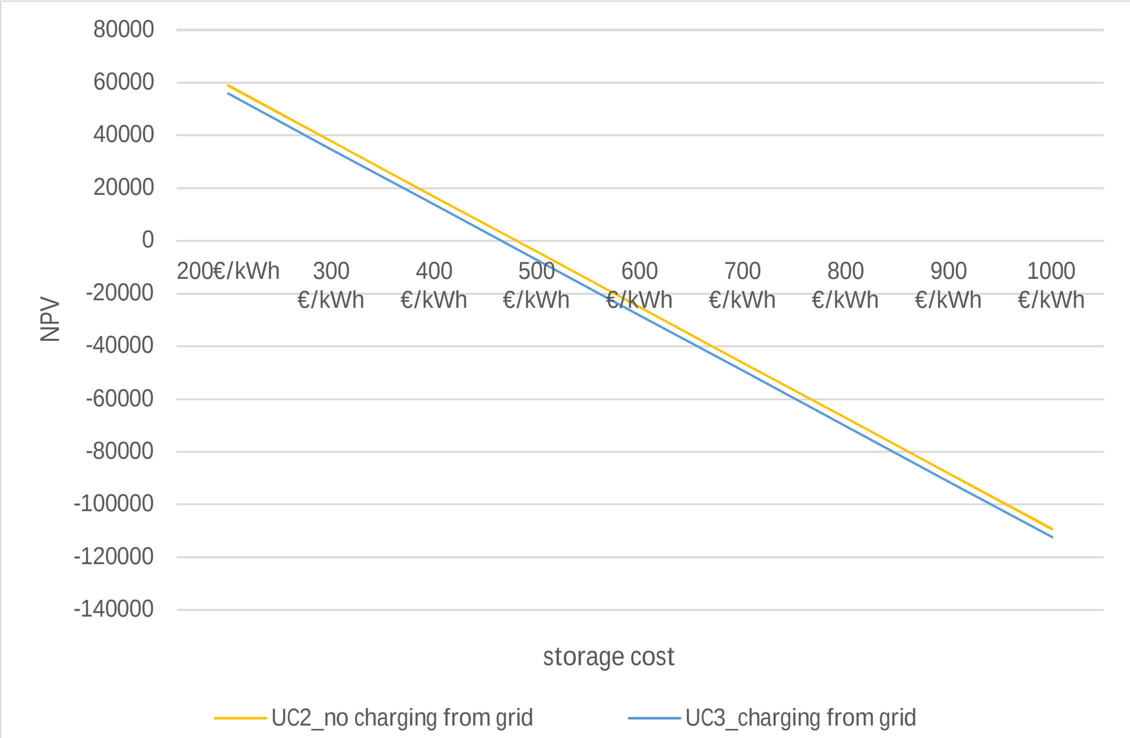

Figure 3 Results of the NPV calculation for UC1 and UC2

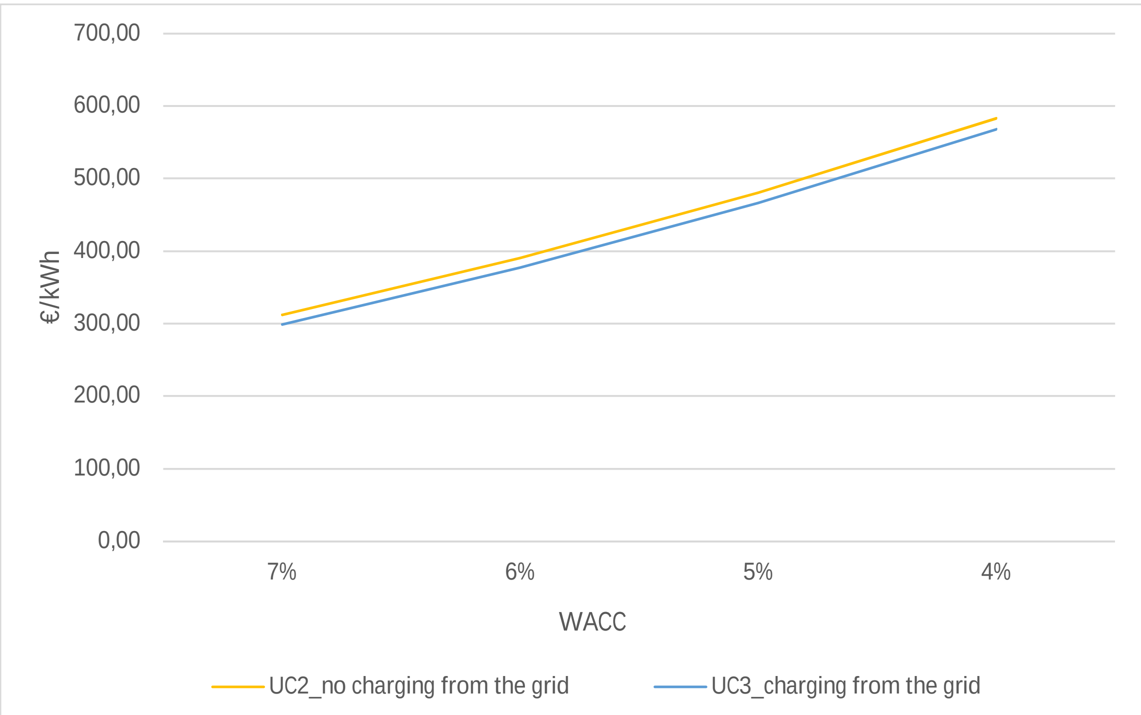

Figure 4: Influence of the WACC on the storage costs for a positive NPV

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1.2.2.3 Key partners

Cener (National renewable energy centre): Cener has taken the technical lead in the project, completing the installation, the energy management system, and the optimization strategies to make the most out of the system installed at Exkal.

1.2.3 Case 3: Compressed air storage in residential district- Lecale, Northern Ireland

This demonstration illustrates the benefits and opportunities of providing electrical storage through compressed air and stored heat to areas of relatively weak existing electrical infrastructure. The location is in Lecale, a semi-rural area in the south-east of Northern Ireland. The demonstration is led by a company called B9 Energy.
The unit will help to demonstrate the ability to store and re-generate electricity with standardised technology components and will validate models for operating the unit within a residential setting. The aim is to both enable the penetration of local sources of renewable energy and to minimise transmission and distribution network reinforcement requirements. It is also intended that the unit will demonstrate applications for compressed air storage within relevant markets including system support services, capacity provision and load-on-demand services (STORY H2020 Project, 2018b). B9 Energy has developed a trading platform to optimize their trading strategies in the different markets.

1.2.3.1 Customer segments and value propositions

Value Proposition for I-SEM market:
Energy trading arrangement- arbitrage: B9 Energy will bid in the I-SEM, the integrated single electricity market arrangement for Ireland and Northern Ireland. Their objective is to arbitrage between peak and off-peak prices with their CAES unit.
Capacity Remuneration Mechanism: in order to ensure that demand of electricity is always met, generators receive a payment for availability (I-SEM, 2018; SEM Committee, 2018).
Value Proposition for the distribution grid operator: the CAES unit is being installed at a distribution grid substation at 33kV/11kV. The unit can contribute to alleviating distribution grid congestion. The 11kV network hosts a tidal turbine, a wind turbine as distributed generation. Also connected to the 11kV network are 300 houses and a fish factory load. The substation itself is also connected to a large solar PV installation. B9 Energy is working closely with the grid operator, Northern Ireland Electricity Networks (NIE).
Value Proposition for distributed generation connected to feeder: The tidal turbine and the wind turbine are liable to curtailment due to grid constraints, due to their location almost at the end of a low voltage feeder. They cause reverse power flows along the network at periods of low demand leading to thermal overloading constraints. The operation of the CAES unit may provide 'load on demand' services that would prevent the curtailment of these units.
Value Proposition for the Transmission System Operator: Eirgrid, the transmission system operator runs a programme called 'Delivering a Secure, Sustainable Electricity System', DS3. A new initiative, for volume capped competitive procurement, would allow demand side units or non-synchronous technologies such as storage to offer system services (Eirgrid Group, 2018c).

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1.2.3.2 Revenue streams

Price arbitrage in the day ahead and intraday Irish electricity market: They will generate electricity and sell it in the market when the price is high, and store energy in the form of compressed air when the price is low.
Capacity remuneration mechanism from I-SEM, a payment for availability in the integrated single energy market.
DS3 remuneration: The programme would entail a service availability obligation, with a proposed six year agreement. The remuneration for energy would be done on pay-as-bid pricing with maximum tariff rates capped to the nearest whole bid.

1.2.3.3 Key partners

Aggregator: B9 Energy have chosen to work with an aggregator in order to manage their access to markets and balancing responsibility. Due to their small scale, and to the fact that they will need to sell energy, they will work with an aggregator. At least a 4 MW capacity is required to participate directly in the I-SEM.
Retailer: at the moment of writing this paper B9 their negotiations are not yet concluded. B9 estimates that they will purchase energy through a third party retailer and they would choose to be exposed to dynamic half-hourly prices following the I-SEM market as closely as possible.
Distribution System Operator: B9 is working closely with NIE during the installation of the CAES unit at the 33kV-11kV substation. After the installation is completed and the unit is running, B9 will need to pay grid fees for both importing and exporting energy to the network. NIE is currently transitioning from being a distribution network operator to being a distribution system operator; so there is some uncertainty regarding grid fees in the future.

1.2.4 Case 4: Suha medium scale storage in residential district.

A medium scale storage unit (170kW, 450 kWh) is connected to a distribution substation in Suha, a residential village grid. Due to the specific set-up characteristics, only 320 kWh of the battery can effectively be used. This assessment considers therefore a battery of 320 kWh and 170 kW with a lifetime of 15 years. The unit is connected to a 400 kVA OLTC MV/LV transformer station of Elektro Gorenjska. The substation contains seven PV units and two households. The grid experiences flows in both directions due to the PV generation. There are 210 kWp of PV installed in the area.

1.2.4.1 Customer segments and value propositions

Elektro Gorenjska: the main user of the battery is the distribution system operator itself. The use cases are mainly related to power quality, peak demand control, reduction of line congestion, and support the neighbouring PV generation to avoid curtailment. In addition, there will be tests to work in islanded mode.
PV producers in the area: curtailment of available PV generation negatively affects the PV producers in the area. The owners receive Feed in tariff incentives for energy produced, which can go as high as 150 €/MWh produced. Storage owner ABB: this partner is also the owner of the battery. The value for them lies in R&D implementation of their technology in a real grid. They gain expertise in how to integrate the technology they provide into a real life distribution network system.

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1.2.4.2 Revenue stream

Power quality: there is no direct revenue stream associated to improvement in power quality. Eventually grid reinforcement would be necessary, but could be deferred through the use of the battery system.

Deferred grid investment: A battery can prevent or post-pone necessary grid investments leading to savings in the DSO's planning budget.

Avoid PV curtailment: curtailed energy is a loss to the system, it has a monetary value on two accounts:

- Curtailed renewable energy receives a compensation for the loss of production.
- The curtailed energy also has a market value.

This monetary value is not covered directly by the DSO, nor is it a savings or a loss of revenue for the DSO. PV curtailment is compensated to users by the TSO. Regulation should encourage measures to avoid RES curtailment whenever possible.

Technology provision and service consulting: ABB has gained valuable experience in how to implement their technology in a network. This will help their sales pitch to other networks and they can exploit their expertise to provide consulting services for similar systems.

"UC2 – R" analyses the economic feasibility of using the entire (low RES scenario)/ part of the (high RES scenario) storage (170 kW) on the mFRR market for a reservation price of 4.43€/mWh and an activation price of 249.5 €/MWh (ELES, 2018). In the high RES scenario part of the battery is reserved for minimizing curtailment. 60% of the total storage capacity is used on the tertiary market in winter, 0% in spring, 40% in summer, and 50% in fall. It is assumed that the reserve capacity is activated 21 times in one year under the assumption that there is no minimum capacity threshold for market participation. The price for recharging the battery is 30€/mWh. Storage costs add up to 500 €/kWh and a feed-in tariff of 0,0462€/kWh is assumed.

The results show that in UC2 –A, arbitrage and self-consumption, the battery is not profitable. If the battery is only used on the reserve market the business case is drastically improved (IRR -6%). For the second scenario, the avoided curtailment of energy creates value which leads to an IRR of -4.9%. A combination of the use for mFRR and to prevent curtailment leads to the best business case (IRR -3.2%).

Table 3: Results of the economic analysis for SUHA

PV capacity	Use case	Market mechanisms	NPV €	IRR
Scenario low RES setting	UC2 - A	Arbitrage, self-consumption	-134,870	-18%
	UC2 - R	Reserve market	-81,470	-6%
Scenario high RES setting	UC2 – A	Arbitrage, self-consumption, curtailment	-79,079	-4,9%
	UC2 - R	Reserve market, curtailment, arbitrage, self-consumption	-67,859	-3,2%

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Figure 8 presents the influence of the storage costs on the IRR. In the low RES scenario in UC2 - A no break-even can be reached, UC2 -R and in the high RES scenario UC2 -A provide a business case (WACC of 5%) if storage costs drop to approximately 265€/kWh. For UC2 –R a cost decrease to 300€/kWh would make the set-up economically feasible.

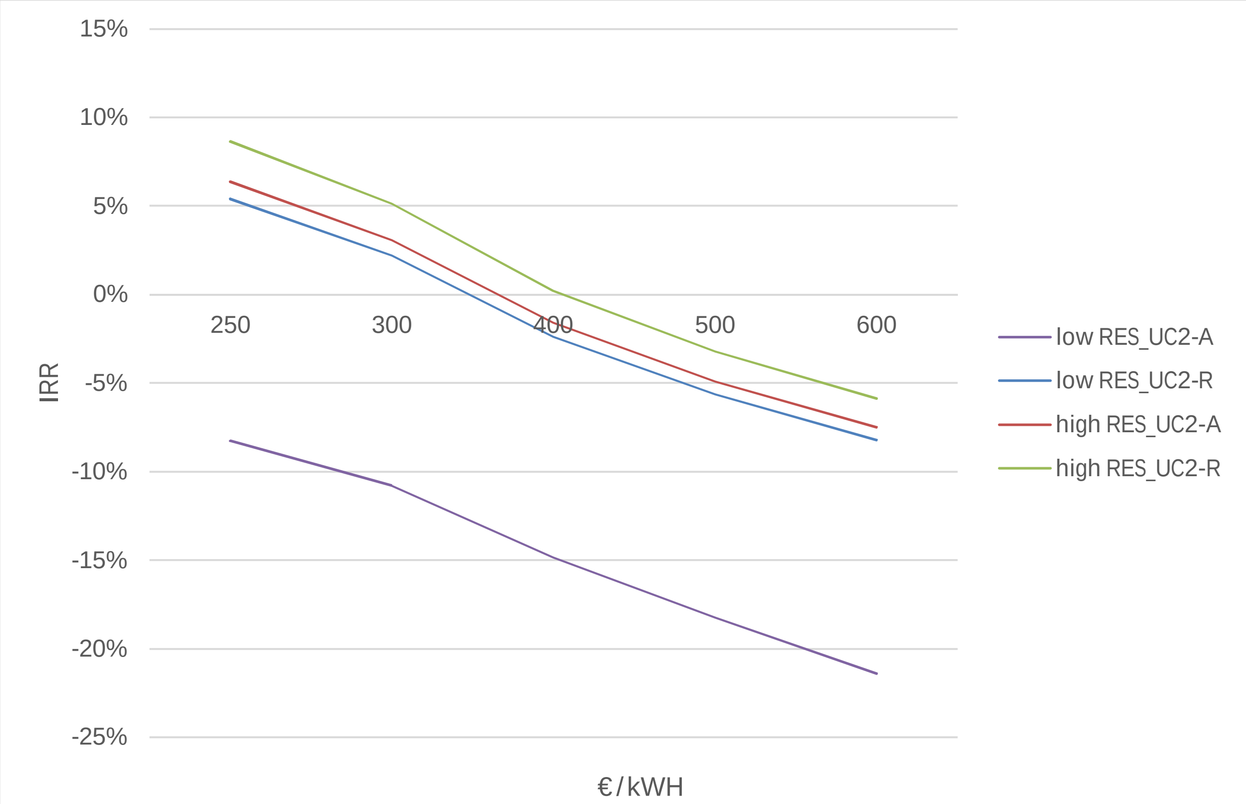

Table 4: Influence of storage costs on the IRR

1.2.4.3 Key partners

ABB: the battery provider and owner is a key partner. They have done the installation of the system in cooperation with the DSO Elektro Gorenjska. The installation process required many visits and time for troubleshooting and integrating the system into the existing grid, information and management systems.

1.2.5 Case 5: Combined heat and power with battery at Beneens industrial site

Beneens is a small industrial site with offices, a wood workshop, and a painting room that are heated using a waste wood boiler fuelled by the waste wood produced on site and from nearby companies. The wood fired boiler has a capacity of 1.6 MW. The produced heat is used by an Organic Rankine Cycle (ORC) installation that generates electricity at a power of 90 kWe and by a high temperature storage tank. This high temperature storage tank provides space and process heating. The

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condenser side of the ORC is connected to a low temperature storage vessel used for low temperature heating of the new offices. The electricity produced is either used directly on site, exported to the grid or stored during the night in the 100 kWh batteries available on site. Approximately half of the electricity is used on-site, the other half is assumed to be fed into the grid. Waste heat of the ORC is used for low-temperature processes, however, only a small fraction of the overall waste heat can directly be used in the factory (demonstration case).

1.2.5.1 Customer segments and value propositions

Beneens as a customer: the installation is first of use to Beneens as a way to cover their own heat and electricity demand. The first value they obtain is a reduced electricity bill as they need to use less electricity from the grid, plus they avoid using gas for heating purposes. They also obtain value by cutting their costs for waste wood disposal. As a wood workshop they would otherwise have to pay a fee to dispose of their waste wood. In addition, they gain intangible reputational value for participating in what is seen as a green project initiative.
SME's in the same industrial complex: Beneens could deliver heat to the other SME's located in the industrial complex, which would improve their business case.
Companies who produce waste wood: Beneens can also dispose of the wood produced by other companies in the vicinity.
Electricity supplier: Beneens can sell surplus electricity to their electricity supplier.

1.2.5.2 Revenue streams

Internal: Savings on waste wood disposal, savings for heat and electricity.
From SME's: Monthly income for heat supply to SME's, approximately 527 MWH/year could be used by the neighbouring companies. This would increase the monthly savings by 611€, assuming a gas price of 0,036€/kWh.
From waste wood companies: income for waste disposal, this is not yet included in the calculation but could improve the business case further.
From Electricity supplier: rebate on their electricity bill.
Revenues from energy injected into the grid: for 0.0352 €/ KWh, which adds up to 1200 € in revenues per month.

Table 5 presents the net present value (NPV) and the internal rate of return (IRR) for the demonstration case. The ORC was about 860 000€ and the extra cost for a compatible boiler for the ORC is 125 000€. O&M costs of 1% of the CAPEX were assumed. A WACC of 5% was chosen. The costs for a thermal micorgrid to connect and sell energy to the neighbours added up to 95 000 €.
The current NPV is negative, however, a small reduction in system costs (<5% of the total costs) would make this use case already economically feasible. The maximum heat that can be sold to neighbouring companies is 527 MWh/year, which would lead to an IRR of 6.3%. If all the waste heat could be sold the IRR would be 37.4%.

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Table 5 Business case Beneens

	Beneens demonstration case	Additional heat use (527 MWh/year)
IRR	4,6%	6,3%
NPV	-41.442 €	134.699

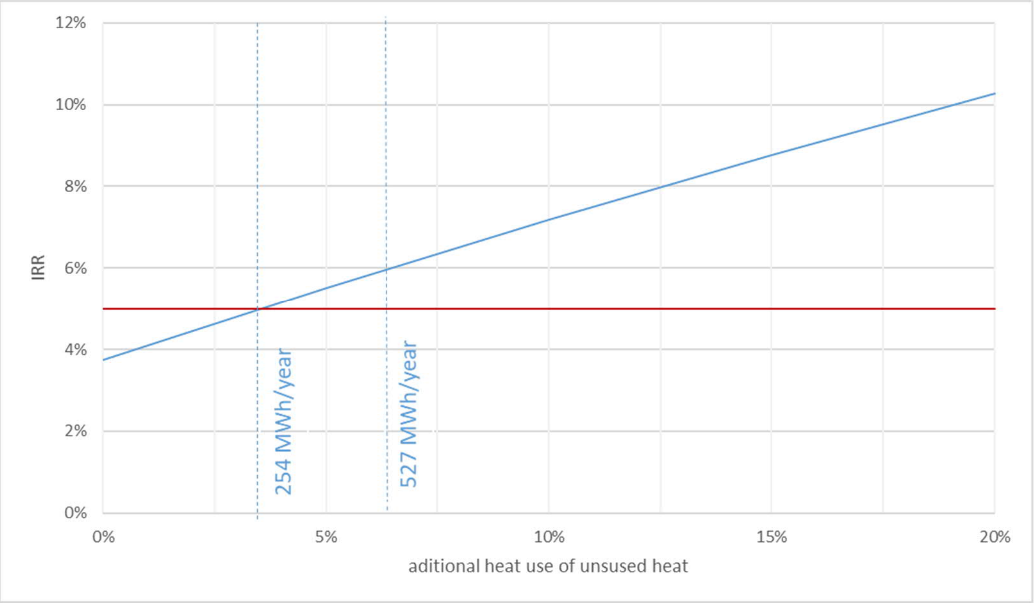

Figure 5: Impact of additional heat use of unused heat on the IRR

1.2.5.3 Key partners

Wood collector company: A key partner for Beneens is a waste wood collecting company. They collect the wood from different companies and transport it to Beneens.
Electricity supplier: Beneens buys electricity and sells back a small surplus to their electricity supplier.

1.3 European Regulatory framework for storage business models

As shown above, the business model of storage is comprised of layered income streams:

- Savings for the owner.
- Services to the DSO
- Services to the TSO
- Services to wholesale market parties.
- Services to a community.

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This section outlines the regulation related to each of these income streams at a European level. Each items is examined in the sections that follow, taking into account that the type of technology of a project will affect the type of services that can be offered.

1.3.1 Savings for the owner

Energy storage for end user optimization is described as a business model archetype of storage in (S. P. Burger & Luke, 2017). Savings for the storage owner as an end-user are possible when the storage asset is used to hedge electricity prices. Two main use cases are identified for savings on a final consumer's electricity bill through the use of storage:

- Storing RES when available: A household where PV panels are installed, for example, could store solar energy generated at noon for use later in the evening.
- Time-of-use price management: A household without solar panels could use storage to take advantage of time of use tariffs to store energy at periods when it is cheaper and use it later when it would be more expensive.

Other use cases that have been identified by literature are: end- user peak shaving, particular requirements in power quality, maximizing self-production and self-consumption, continuity of energy supply, and electric vehicle integration (Ease/Eera, 2017) (Fitzgerald, Mandel, Morris, & Touati, 2015).

From a regulatory perspective this use case is enabled in legislation first through the definition of which parties are enabled to own storage; and second through the tariff regime set in place.

1.3.1.1 Ownership of storage

Ownership of storage in the EU Articles 2(6) and 2(7) of the Clean Energy Package Directive (EU 2019/944) entitle final consumers and citizen energy communities to engage in the activity of storing and selling electricity. Article 15a in the Directive, pertaining to active consumers, states that 'Member states shall ensure that final customers are entitled to generate, store, consume and sell self-generated electricity in all organised markets individually or through aggregators without being subject to disproportionately burdensome procedures and charges that are not cost reflective' (European Parliament and the Council of the EU, 2019). It is important to note that in the same Directive, article 36, it is stated that 'distribution system operators shall not own, develop, manage, or operate energy storage facilities'.[18] However, the same article goes on to exceptionally allow DSOs to own storage after approval from their regulator, if the storage assets are fully integrated network components after the DSO has opened a tender that has gone unanswered by the market and it is proven that the asset is necessary for the secure operation of the system. Even in this instance, the DSO shall not be allowed to buy or sell electricity in the electricity markets. Article 54 limits the ownership of storage assets for TSOs with similar exemptions as for DSOs.

where such restoration measure starts immediately and ends when regular re-dispatch can solve the issue; and (d) not used to buy or sell electricity in the electricity markets, including balancing.

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1.3.1.2 Grid Tariffs

Grid tariffs are the regulated component that a final consumer pays for using the network. The overall bill consists of network tariffs for both transmission and distribution, taxes and levies, and energy consumption. The type of grid tariff that a storage asset pays to use the network has a direct impact on the business case of storage. According to EASE, the European Association for the Storage of Energy, several European countries foresee charges for storage for both withdrawing and injecting energy into the network, and grid charges have a substantial impact on the overall cost and profitability of energy storage devices (European Association for Storage of Energy, 2017). Therefore, this subsection describes the types of grid tariffs in current practice and regulatory proposals in the EU as compared to Finland.

Grid connection fees occur once when a new user requests a connection to the grid. While grid tariffs are recurring tariffs for the continued use of the network, usually billed on a monthly or yearly basis. DSOs obtain their revenue from the regulated tariffs that they charge to consumers. The methodologies for tariff design vary across Europe. Network tariff designs are a mix of a capacity component related to the size of a grid user's connection to the network (expressed in kW) and a volumetric component, related to the energy use throughout a period of time (expressed in kWh). TSO network tariffs lean towards being charged per capacity. While, most European DSOs' revenue is currently based on volumetric tariffs, i.e., 69% of the revenue for households, 54% for small industrial consumers and 58% for large industrial consumers (Meeus & Nouicer, 2018).

Article 15(5) of The Directive (European Parliament and the Council of the EU, 2019), states several rights for owners:

- The right to a grid connection within a reasonable amount of time after request;
- Active consumers should 'not be subject to any double charges, including network charges, for stored electricity remaining within their premises or when providing flexibility services to system operators.'
- They are not subject to disproportionate licensing requirements or fees.
- They are allowed to provide several services simultaneously, if technically feasible.

The clean energy package, in the regulation of the internal market for electricity (from now on quoted as 'The Regulation') in article 18, states that 'The network charges shall not discriminate either positively or negatively against energy storage or aggregation and shall not create disincentives for self-generation, self-consumption or for participation in demand response' (European Parliament and the Council, 2019). Furthermore, article 18 states that once smart meters have been rolled out regulatory authorities shall consider time-differentiated network tariffs to reflect the use of the network.

It is clear in Article 15 in the Directive, that double charges for storage should not occur, including network charges. While the Regulation in article 18 states that network charges should not discriminate positively or negatively against energy storage assets. Nevertheless, the exact tariff design, meaning the combination of capacity and volumetric tariffs, is left up to each member state.

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1.3.1.3 Energy tariffs

The energy tariff is the de-regulated component of the full electricity bill of a consumer. It is the price per kWh that the consumer pays. Traditionally, consumers have paid flat tariffs, a single price for every hour of the day, or time-of-use tariffs usually divided into peak and off peak prices throughout a day. This price is key to the business case of energy storage, which relies on savings obtained from energy price differences. Article 11 of the Directive ensures that final consumers will have access to dynamic electricity price contracts from their suppliers (European Parliament and the Council of the EU, 2019). In Finland, although the hourly tariffs are available, very few clients are finally interested of using them (Ruokamo et al 2019).

1.3.2 Services for the DSO

Distribution system operators can use storage assets to support their grids. A list of possible services for DSOs is found in (Ease/Eera, 2017): capacity support, contingency grid support, distribution investment deferral, distribution power quality, dynamic local voltage control, intentional islanding, limitation of disturbances and reactive power compensation.

DSOs have not traditionally procured energy for grid services. This is a new concept for them, that is now enabled by EU level legislation, but has yet to be transposed into local legislation and internal management procedures within each DSO. Article 18 of The Regulation states that tariff methodologies should provide incentives to distribution system operators for a cost-efficient development of their network including through the procurement of services (European Parliament and the Council, 2019).

1.3.3 Services for the TSO

Transmission system operators can also make use of storage services to maintain grid balance. Storage can provide fast acting reserves that can participate in ancillary services markets at different time frames. Namely, storage can provide frequency containment reserves, frequency restoration reserves, frequency stability and black start services to a system operator (Ease/Eera, 2017; Fitzgerald et al., 2015).

1.3.4 Services for wholesale market parties

Utilities, generators and other wholesale market participants base their bids on consumption and generation forecasts. When these forecasts have errors they must cover the differences by participating in the wholesale markets. Storage assets can be used to cover these forecast errors and to arbitrage price differences between peak and off-peak hours (Confais & Van Den Berg, 2017).

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Service provision by final consumers is enabled by the Regulation in Article 3e, whereby 'market participation of final customers and small enterprises shall be enabled by aggregation of generation from multiple power-generating facilities or load from multiple demand response facilities to provide joint offers on the electricity market'.

1.4 Conclusion

In this section the business models for storage used in the STORY project are classified according to the level of resource aggregation, and the stakeholders that each demo creates for different stakeholders. In terms of aggregation, storage resources can either be used in isolation behind the meter, coupled to other neighbouring prosumers for self-optimization; or they can be designed to provide services to other market participants. The main value created depends on the actors that can use each specific assets, from the storage owner or local community, to the grid operators at distribution and transmission level, to other market participants at wholesale level. The regulation enabling each business model at European level was also described. The main issues that storage projects face is the legal definition of storage, the design of network tariffs, DSO participation in the project, and the enabling market design.

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2 Annex 2: The technology provider's perspective on business models for storage

Published as: Chapter 3. State of the art in business models: business model mapping. In: BRIDGE-Horizon 2020, (forthcoming). BRIDGE Business Model Working Group First Annual Report.

Nico Keyaerts[a]

[a] Vlerick School of Business, Bolwerklaan 21, B32, 1210 Brussels, Belgium

2.1 Introduction

According to a 2015 survey of the European distribution system operators (DSOs), an overwhelming majority of DSOs are convinced that the future energy system will be much more decentralized than today, and consumers are going to be much more active than they are today. Furthermore, a significant number of DSOs believe that going off-grid will be a plausible alternative for energy consumers by 2020, being enabled by the rapid development of batteries (Tackx & Meeus, 2015). The energy sector will not only have to cope with that change, it will have to transform itself to allow new businesses to emerge while at the same time it has to provide the extraordinary reliability of energy services that customers have become accustomed to.

Even though energy storage technologies have existed for decades, for instance pump hydro storages, gas storages, thermal storages and fuel cells, the economics supporting the deployment of these and more novel battery technologies in the future energy supply chain are still largely unexplored.

The economic questions concerning energy storage are twofold. The first concern is the value creation by storage systems. This value added is determined by the services that energy storages are able to provide to the energy system (Rocky Mountain Institute, 2015). Many research and demonstration projects focus on the value creation by evaluating possible business cases in which storage indeed creates positive value. The second concern is the value capturing when there is indeed value created. In other words how do businesses appropriate part of that value in a competitive or contestable or regulated market and how do they share value along the value chain, considering the high upfront costs that make entry of outsiders more difficult (Pollitt, 2015)?
The first question, which is not further explored in this chapter, has been addressed by e.g. the Rocky Mountain Institute (2015) or Pollitt (2015), which concludes that positive business cases exist when multiple services are offered by a storage system. The Rocky Mountain Institute considers thirteen possible services, such as optimizing self-consumption, provision of reserves or congestion relief. These services are provided to three customer groups, which are the final customers, the grid companies and energy service companies.

This work deals with the second economic concern by mapping the business models of existing companies that offer energy services at the edges of distribution grids. Our mapping is based on information on 20 businesses collected by the Horizon 2020 projects participating in BRIDGE using a reporting template that simplifies and extends the well known business model canvas by Osterwalder and Pigneur (2010). Our method is therefore compatible to the mapping that has been done e.g. by Burger and Luke (2016), who have mapped business models for demand response, for solar PV and for storage systems, but differs in the choice of archetypical mapping dimensions. The

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interested reader can find a review of the limited available literature on business models for energy services in the same work by Burger and Luke.

This chapter is further divided in four sections, including this introduction. In section two, we discuss the survey that has been used to collect data on the business models, highlighting the strengths and weaknesses of our method. In section three, we discuss the mapping of business models according to several archetypes. Final conclusions are offered in section four.

2.2 Business model mapping approach: extending and simplifying the business model canvas

In this section, we discuss first the framework that is used to collect information regarding a company, regarding the business model of that company and regarding the internal and external factors that have driven business model innovation. Second, we discuss the strengths and limitations of the approach.

The framework that serves as a common reporting template consists of three parts that together allow an ontological description of the business model of a company. Part 2 of the template corresponds to a simplified version of the traditional business model canvas by Osterwalder and Pigneur. The other two parts extend the traditional business model canvas. Part 1 deals with describing the concerned company in general terms, whereas Part 3 looks at factors driving business model innovation to adjust for the static nature of the business model canvas. Each of these three parts is now discussed in more detail.

2.2.1 Part 1: the company passport

This part of the framework identifies some facts and figures about the concerned company to facilitate the group effort for data collection. It is important to collect these basic data to ensure the consistency of and a common context for what is reported in the other parts of the framework when going from the stage of data collection to the stage of data analysis.
The company passport includes the full name of the company and addresses questions regarding the part of the energy industry in which the company is active. It reports on the main locations of the activities and on the maturity of the company in terms of its size and its market positioning as an incumbent or new entrant. Finally, this part also addresses the legal status of the company, which could be privately owned or state-owned, regulated or not.

2.2.2 Part 2: simplified business model canvas

The second part of the framework deals with the questions that are associated with a company's strategy to capture a part of the value. While there exist several tools to help companies to structure their thinking on their business model, with different degrees of sophistication, for the purpose of this work, it was decided to base the questions on the standard business model canvas as depicted in Figure 6.
The standard business model canvas has nine boxes, which are: key partners, key activities, key resources, value propositions, customer relationships, channels, customer segments, cost structure

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and revenue streams. These nine boxes challenge the user of the canvas to think deeply on each of these items, which is too sophisticated for the current purpose as the goal is not to design an actual business model, but to report on existing innovative business models from publicly available sources. For that reason, the nine boxes are transformed into ten questions covering the five main dimensions of a business model: interactions with customers, value proposition, the supply chain, the costs and the revenues.

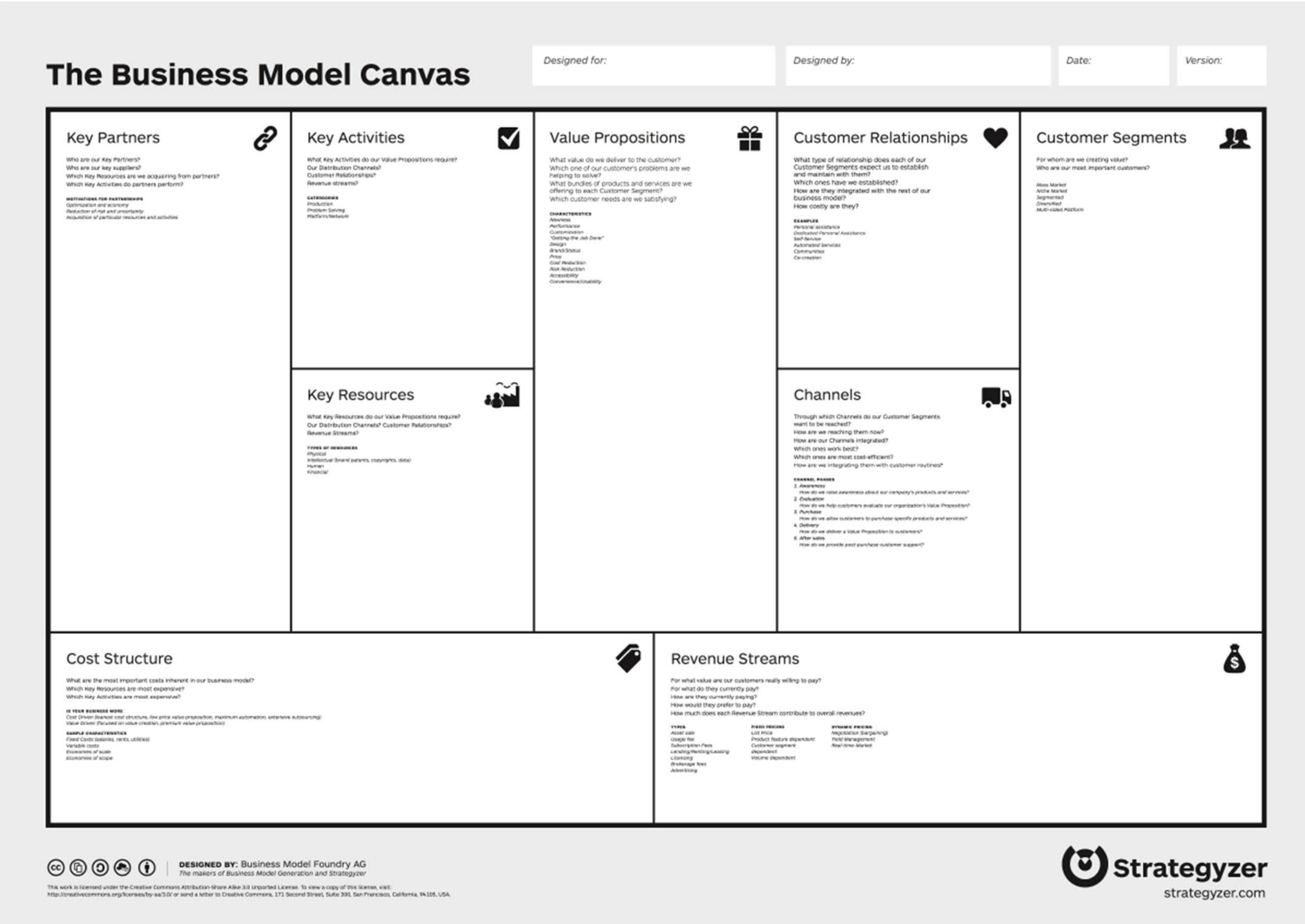

Figure 6: Traditional business model canvas (Oesterwalder and Pigneur, 2010)

Question 1. Which customers/customer segments are targeted?
This dimension addresses which customers or customer segments the business is targeting. Based on our sample of mapped business models, three types of customers can be distinguished: 1/ end customers which includes residential, commercial and industrial consumers, 2/ market-based energy service companies which includes e.g. suppliers and aggregators, and 3/ regulated grid companies.

Question 2. How are the customers reached?
A secondary question regarding interacting with customers addresses how a business can use different sales channels and marketing channels to reach its customers.

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Question 3. What is the value proposition?
Companies differentiates themselves through their value proposition for customers. This value proposition can be for instance be based on operational excellence (lower your bill), customer intimacy (easy access to services via a single platform), or product leadership (superior technology).

Question 4. How is the offer delivered?
This secondary question regarding the value proposition addresses what companies do to deliver that offer. This could for instance be continuous innovation of products.

Question 5. What are the key activities?
A company can try to maximize the value that it appropriates by covering all activities in the value chain or it can focus on a subset of the activities. Based on the sample of business models, we distinguish four degree of involvement in the value chain: 1/ advising customers, 2/ turnkey solutions, 3/ financing services, and 4/ operation services.

Question 6. Who are the key partners?
The activities that are necessary to create value for the customer but that are not internalized within a company have to be performed by other actors in the value chain with which the company has to partner up.

Question 7. What are the most important fixed costs? & Question 8. What are the most important variable costs?
To deliver their offering, companies have fixed costs such as office space or employees and variable costs that vary with the output level of the company. Some costs might be impossible to avoid, whereas other costs might be reduced e.g. by economies of-scale.

Question 9. What is the basis of pricing for the offering?
This fifth dimension addresses the revenue model of the company, which has two components: the basis for the pricing and how customers are charged. The offering could be priced based on an access model, like the peak capacity requested, or based on the consumption volume or a combination of both.

Question 10. How are customers charged?
Companies can charge customers for instance through monthly fees, one off payments, distinct installation fees and maintenance fees.

2.2.3 Part 3: Internal and external opportunities

The business model canvas based framework in part 2 provides only a static picture of the business model of a company. However, in reality, business models are dynamic, changing over time because of internal and external factors that drive change in the company or industry. Part 3 of our common framework takes account of these dynamics.

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In general, there are three types of events that drive business model innovation: 1/ internal events, 2/ market events, and 3/ policy and regulatory events.

A. Internal events
Examples of internal events that drives management to change the business model of the company include for instance technological innovation or the entry of new management.

B. Market events
New entrants, market saturation or industry consolidation could all drive a company to adjust its business model.

C. Policy and regulatory events
The provision or abolition of economic incentives can be a reason for adjusting the business model. Policy objectives such as for instance penetration targets for smart meters could kick start emerging businesses.

2.3 Strengths and limitations of the approach

The method for collecting the information on which we base the business model mapping relies on accurate reporting of publicly available information by outsiders.

2.3.1 Strengths of the approach

- The common reporting template covers a comprehensive ontological view of business models and the necessary adjustments have been made to capture the dynamic nature of business model innovation
- The common reporting template provides a way to collect and share information among a large group of partners.

2.3.2 Limitations of the approach

- The decentralized approach makes quality control at the input side challenging.
- The completion rate of the templates in our sample differs significantly, requiring additional information to be collected before further analysis is possible.
- The selection criteria for considering a company as innovative are interpreted differently and often the reported information does not highlight the innovativeness of the business model.
- The collected information regarding business models that ultimately failed was too limited to consider in this work.

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2.3.3 Corrective measures

- The business models of companies active in energy storage services, which are the core interest of the STORY project, have been completed and have been validated to the best of our ability; any interpretation errors are ours.
- The business models of companies active in other energy services have been used with due caution accommodating for their incompleteness; it is left to the interested reader to further complete the reports, which can be found in the annex, before doing additional analysis.

Energy Management Systems	Storage systems	Aggregation & retailing	Distributed generation	Market facilitation
Beegy Bosch Smart Home* Smappee*	Caterva Senec.ies SmartStorage Sharp Sonnen STEM Tesla UKPN Younicos*	CarbonCo-op CEA Ecopower* Restore Tempus Energy	Biolectric MyGreenHeating SolarCity	Datahub by Fingrid* Ingrid*

*Excluded from further analysis

Table 6: Overview of investigated businesses according to principal activity

2.4 Business model mapping

There are several ways to map business models. It is well established practice to classify businesses according to value proposition archetypes such as operational excellence, product leadership or customer intimacy. Business models can also be classified according to revenue model archetypes such as retail models with one-off payments, subscription models with usage fees or transaction models with commission fees.

Our mapping is based on two other archetypical dimensions of a business model, which are the degree of integration of the value chain, and the customer segments that are serviced. The integration of the value chain is further divided into advising on energy services, financing energy technologies, offering turnkey solutions, and operating the energy technology. The customer segments are further divided in the business to consumer segment (B2C), which includes residential, commercial and industrial consumers, and the business to business segment (B2B), which includes commercial services to energy market players and regulated services to grid companies.

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In the report, we first introduce the businesses in our sample. Next, we further introduce the two-dimensional mapping space before discussing the resulting mapping of the business model.

2.4.1 The sample of energy service businesses

Data has been collected for a total of twenty one businesses that are active in the energy sector Table 6. Of these twenty one companies, six business models have been excluded from further analysis (marked with *) because insufficient information was available or because the business model is in an R&D stage. Below, we briefly introduce all businesses in our sample based on the information collected in the common reporting template. These are only a few examples in the market, the ones for which better quality information could be found.

Energy management system (EMS)
Beegy is a startup company from Germany that offers a smart user platform solution that manages all distributed energy services at home. The company targets the B2C, currently focusing on residential customers with plans to expand the offering to commercial and industrial customers. Beegy offers turnkey installations as well as the optimization of the customer's distributed energy systems.

Bosch Smart Home* is a new subsidiary of the German Bosch group that brings together all activities related to energy management systems, leveraging the expertise in consumer technology from the incumbent Bosch group. The company sells turnkey smart home technologies for monitoring and managing energy consumption in a smart home. The offer targets the residential segment of the B2C market.

Smappee* is a Belgian startup that sells home energy management systems to the niche of residential and commercial customers in the B2C market that value high end designer technology. Smappee received economic incentives for developing its innovative software to monitor energy consumption in real time and on the appliance level. It furthermore leverages the experience of its management in the more mature market for industrial energy management services.

Storage systems
Caterva is a German[19] startup that offers batteries to residential customers either selling them or renting them. Customers have the option to have their battery managed by Caterva, who uses the flexibility to offer primary control reserves to grid companies in the B2B segment of the market. The additional revenue for Caterva is shared with the customers who signed up for the virtual community storage program through lower monthly fees.

Senec.ies is a German company that sells batteries in the B2C segment of the market, mainly focusing on increasing self-consumption by residential prosumers. Additionally, the company

[19] It is to be noted that the demand for battery systems in Germany is partly driven by the economic incentives for consumers to invest in solar PV combined with storage. This German policy is driving, at least to some extent, all German business models focusing on storage and distributed generation for the B2C segment of the market.

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aggregates batteries to offer regulated services, i.e. negative regulating power, to the grid companies. The “negative regulating power” provides free energy to the customers who subscribe to the program by paying a one-off fee.

SmartStorage by Sharp is a subsidiary of the electronics company Sharp that sells battery systems in the United States. They focus on energy consumption optimization solutions for commercial and industrial consumers in the B2C segments such as schools or hospitals.

Sonnen is a German company that primarily sells plug and play batteries to residential customers. Additionally, Sonnen offers their customers to subscribe for a monthly fee to the SonnenCommunity to trade energy services among the members of the community, setting up a parallel market place.

STEM is a US based company that sells and operates batteries B2C and aggregates the batteries it operates to service the B2B segment of utilities and grid companies. Customers pay monthly fees for the batteries.

Tesla is a US based company that sells high end electric cars and batteries for residential behind the meter optimization. Tesla follows the product leadership model. The residential battery activities fit in the company’s strategy to optimize the used capacity in the battery factories and to achieve learning effects and economies of-scale.

UKPN is a distribution system operator from the UK that also operates private grids. UKPN is operating a grid-scale storage targeted to the B2B segment and offering commercial services as well as regulated services. The company has received economic incentives as part of an innovation program.

Younicos* is a storage systems company that offers integrated turnkey solutions to B2B customers.

2.4.2 Aggregation & retailing

CarbonCo-op is a non-profit cooperative of residential consumers in the greater Manchester area in the UK that advises consumers and operates their energy consumption to deliver services to the B2B segment. The revenues made from regulated services for the DSO are shared among the cooperative members. Members pay an annual membership fee, and receive revenues according to their contributions to the B2B services.

CEA or Cooperativa Eléctrica de Alginet is a Spanish non-profit cooperative that has been the local distribution company and retailer since 1930. Alginet is the first municipality in Spain to implement a smart grid to offer better energy services to residential and commercial consumers, including the optimal operation of distributed generation. The smart grid activities are still in the R&D stage.

Ecopower* is a Belgian cooperative that invests in renewable energy and is aggregate prosumers into a virtual power plant to target B2B for commercial or regulated services. However, those aggregation activities are in the R&D stage.

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REstore is a Belgian aggregator of industrial and commercial energy consumers. The flexibility of their customers is offered in the B2B market for commercial services and for regulated services such as primary reserves. Flexible customers receive fixed payments to reserve their capacity and variable payments when their flexibility is activated.

Tempus Energy is a company that operates a trading platform that matches its B2C customers to the best energy offers available. It wants to offer B2B services from aggregated demand response.

2.4.3 Distributed generation

Biolectric is a Belgian company that offers turnkey solutions for distributed generation to industrial customers in the B2C segment. Flemish customers, the main target group, benefit from economic incentives and net metering, which makes distributed generation attractive for them.

MyGreenHeating is a UK based company that offers financing of innovative heating concepts for the B2C segment, focusing on social housing and homeowners. Customers can benefit from customized payment plans and economic incentives for renewable heating.

SolarCity is a US based company that offers financing and turnkey solutions for solar PV. It services the B2C segment, focusing on residential and commercial customers that want to lower their energy bill. SolarCity designs, manufactures and installs solar PV systems and it partners with Tesla to offer combined solar PV and battery packages. Customers benefit from several federal and state economic incentives.

2.4.4 Market facilitation

Datahub by Fingrid* is a subsidiary of Fingrid, the Finish transmission system operator. It will operate the data hub for the whole country and will target the B2B segment. Further information is unavailable at the time of writing this report.

Ingrid* is a concept for a market platform to facilitate the integration of renewable distributed generation to the benefit of energy customers and the energy system.

2.5 The two dimensions of the mapping space

In this section, the two dimensions of the proposed mapping space are consecutively introduced, using the example of energy storage.

2.5.1 Dimension 1: degree of integration of the value chain

In their efforts to capture value, companies have to decide which parts of the value chain are internalized in the company, and for which parts it relies on formal or informal partnerships. Here we distinguish four activities in the value chain for providing energy services.

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- Advising: customers need to be aware of the value that energy storage offers to them to make them interested in using storage assets.
- Financing: companies can help with the financing of storage systems that require significant upfront investment. This could include third party ownership models in which the user / host of the asset differs from the owner.
- Turnkey: companies cans sell, design and install storage systems at the premises of the customer. The customer controls the storage unit. Often the company offers maintenance services, inclusive to the purchase or optional at a premium.
- Operation: companies can offer to operate the storage system to the benefit of the customer who owns or hosts the asset.

2.5.2 Dimension 2: customer segment serviced and services provided

- Companies can typically offer their products to end users in the B2C segment or to businesses who use the products to offer themselves other products in the B2B segment.
- In the B2C segment storage systems are offered to residential, commercial or industrial customers who use the storage to optimize their own energy consumption behind the meter.
- In the B2B segment storage systems are offered to commercial and regulated energy market players to provide commercial and regulated services.
- Companies might target both the B2C and the B2B segments when the asset is used to offer behind the meter services to end customers and commercial and regulated services to the energy market players.

2.6 Business model mapping observations

The mapping of the fifteen retained companies in our sample is provided in Figure 7. Note that the positioning in the space is approximate and illustrative, it is not meant as an exact representation of reality.

Following the analysis of the business models and the positioning of the businesses in the two dimensional space, four observations can be made. These observations are consecutively discussed below.

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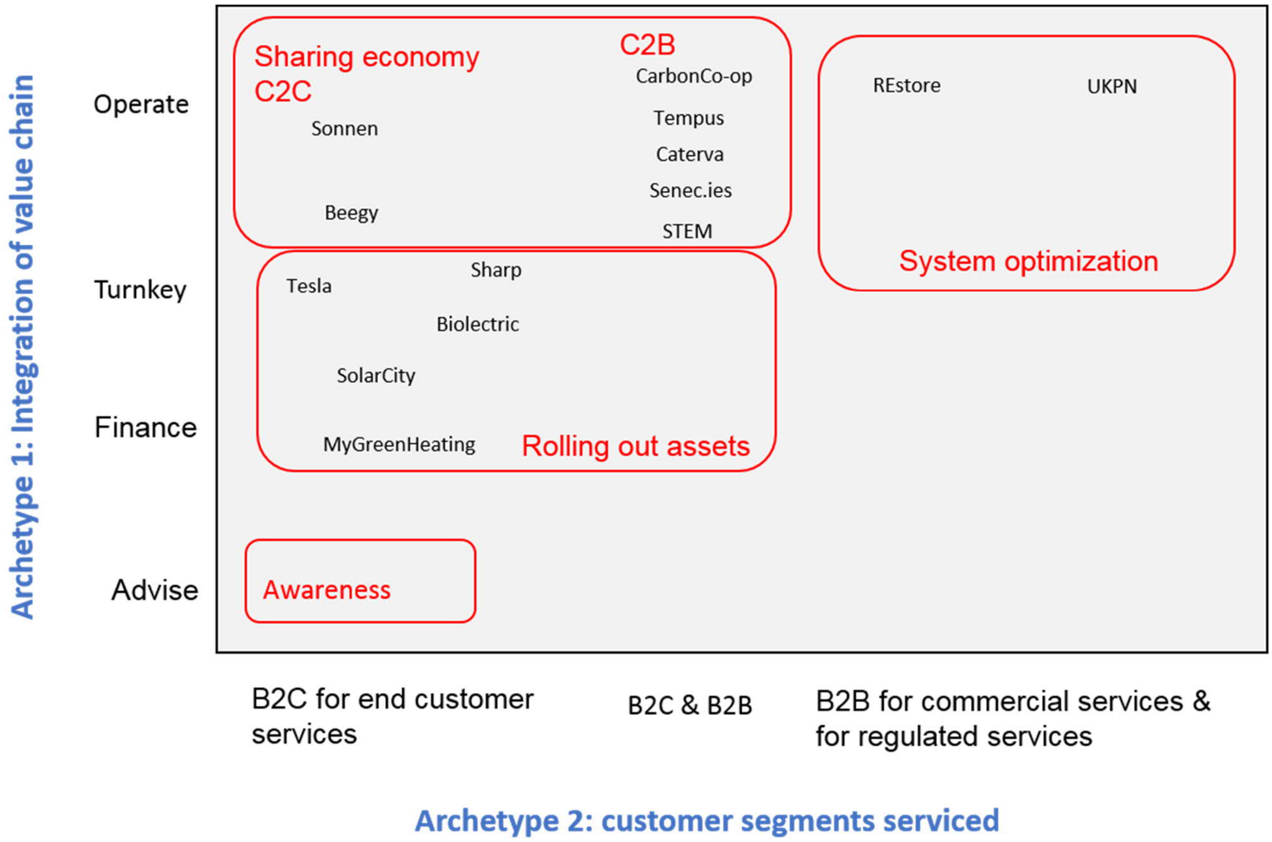

Figure 7: A typology of business models for storage [the positioning in the mapping space is for illustrative purposes only]

Market gap for awareness

It is striking that in our limited sample there are no energy service companies represented that are dedicated to raising awareness about the value of storage systems.

Rolling out assets

The majority of business models are orientated towards rolling out assets either by selling them as turnkey solutions or by financing them. The many economic incentives for customers are a major driver for these business models. Some of these businesses[20] additionally offer operation as an option; these businesses have been depicted in the sharing economy group in Figure 7.

Sharing economy: C2C & C2B

A significant number of business models bring together a great many small customers in cooperatives or communities. By collaborating, these small customers can convert their distributed assets into an offer of commercial and regulated services for the market players in what could be called the consumer to business (C2B) segment, or they provide consumer to consumer (C2C) services. These business models fit in the evolution towards a sharing economy, in which collaboration and empowerment at the consumer level gains importance.

[20] The business in the sharing economy group that also fit in the rolling out assets group are: Sonnen, Beegy, Caterva, Senec.ies and STEM.

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System optimization

Finally, a number of business models focus on optimizing the energy system with the companies operating the assets offering commercial and regulated services to the energy market players. Notwithstanding the limitations of our small sample of businesses, there seems to be room for more storage businesses that have the optimization of the energy system as their core activity. Possible barriers for these businesses include energy market rules and regulatory constraints.

2.7 Conclusions

This chapter addresses the potential business models to capture value in the business of energy related services, primarily looking at the case of storage systems. Using a common reporting template, a group of European research projects representing a significant cross-section of Europe have collaborated to collect data on innovative business models.

These business models have been analyses to identify archetypes that can be used for further research. The analysis resulted in a mapping of existing businesses in a two dimensional space with on the horizontal axis the customer segments served and on the vertical axis the degree of integration of the value chain.

Based on this mapping, four observations have been made. First, there is a potential gap for energy service companies advising customers about the value of storage systems. Second, the majority of businesses focus on deploying assets through selling turnkey solutions and/or by financing the assets to remove the barrier of the significant upfront cost. The deployment is strongly focused to the B2C segment. Third, several business models embrace the sharing economy concept allowing consumer to offer services to other consumers (C2C) or to market players (C2B). Fourth, there seem to be few companies that are oriented towards the B2B segment for optimizing the energy system. More elaborate analysis on an expanded dataset is however necessary to confirm these observations.

2.8 Acknowledgement

The authors would like to thank all BRIDGE partner projects for their efforts to collect data on innovative businesses in the respective countries that the projects are active in. In particular, we thank Stefan Haenen, Kris Kessels, Urs Warthmann, Xavier Martinez, Raphael Hollinger, Costas Kalogiros, Rowena McCappin, Dimitris Zafirakis, Xu Yueqiang, Pierre Selmke, Tine Stevens, and Pasi Pussinen.

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3 Annex 3: The aggregator's perspective on storage business models and regulation

Ariana Ramos[a]
[a] Vlerick School of Business, Bolwerklaan 21, B32, 1210 Brussels, Belgium

Abstract. Consumers participate in electricity markets through intermediaries. Until recently they participated as electricity buyers through their retailers. Now, prosumers can sell energy and flexibility in the market through a new intermediary called an aggregator. The introduction of a new intermediary between the consumer and the electricity markets creates friction with the existing retailer. The independent aggregator modifies the consumption profile of consumers already served by a retailer. It is shown in this paper that retailers and aggregators have an inherently different core business model. A retailer is a dealer-type of business while an aggregator is a platform-type of business. The relationship between the two parties in the electricity market is explained. It is found that an independent aggregator causes structural open positions for a retailer. Current practices in selected European countries are presented. The differences revolve around information disclosure and transfer of energy payments.

3.1 Introduction

The clean energy package for all Europeans places consumers at the centre of energy markets. The package 'empowers European consumers to become fully active players in the energy transition and fixes two targets for the EU for 2030 a binding renewable energy target of at least 32% and an energy efficiency target of at least 32.5%' (European Commission, 2016a). Electricity markets are intermediated due to their wholesale scale. Most consumers do not observe real time electricity prices, and their information and reaction capabilities are limited. This paper explores the relationship between the intermediaries that currently enable consumers access to markets: the retailer and the aggregator.

A retailer, also called a supplier, is an entity who buys energy from producers and resells it to final consumers (European Commission, 2016c; Steiner, 2000). Traditionally consumers have bought energy from retail suppliers who act as intermediaries between them and the larger electricity markets. Retailers buy energy either directly from generators or from the wholesale market exchanges and re-sell it to consumers.

A new market player, called an aggregator, has emerged. Consumers now have the capability to also sell energy and flexibility though at a much lower scale than conventional generation. But, they find that the mechanisms to do so are not available. Aggregators are defined in the Directive of the European Parliament and of the Council on common rules for the internal market in electricity (from now on 'the directive') as a 'market participant that combines multiple customer loads or generated electricity for sale, for purchase or auction in any organised energy market'. A specific type of aggregator called 'independent aggregator' is also defined as 'an aggregator that is not affiliated to a supplier or any other market participant'. The introduction of independent aggregators enables demand response in markets where retailers are not already doing that.

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The independent aggregator modifies the consumption profile of consumers that are already served by a retailer. This causes an imbalance for the retailer, the energy that the retailer purchased no longer matches the energy required by consumers. Therefore a conflict arises between the two intermediaries. This paper analyses the conflicts that arise between the independent aggregator and the retailer. In order to do so, first their business model propositions are compared, and then their conflict in the electricity market is explored.

This paper uses a qualitative approach for identifying the business model and conflicts between the retailer and the aggregator. The business model work is built using the business model canvas as a template and it is based on a literature review complemented by three workshops carried out with STORY project members; and a workshop with external Advisory Board members of the project.[21] In addition, phone interviews have been carried out with three project developers for projects that involve consumer participation in energy markets. Workshops and phone interviews have proven to be effective methods to study business models for innovative services in the energy sector (Hall & Roelich, 2016; Lampropoulos, van den Broek, van der Hoofd, Hommes, & van Sark, 2018; Richter, 2013). Two case studies of demonstration projects involving the use of an aggregator are presented to exemplify the business model archetypes, one is a local energy community with residential demand response in Belgium, and the second one is a Compressed Energy Storage unit located in Northern Ireland. The conflicts between the two parties are then abstracted from the previous discussion and complemented through literature and available evidence on the subject.

Section 3.2 first explores the business model of the retailer and the aggregator in subsections 3.2.1 and 3.2.1 respectively. Section 3.2.3 compares the two business models in terms of their basic building blocks. The conflicts between the roles of the retailer and the aggregator are then explored in Section 3.3 in terms of the relationship between the aggregator and the retailer; and the aggregator and a balance responsible party representing a retailer. Current practices regarding the conflict between the two parties are explored for representative countries in section 3.4. Finally, conclusions and policy implications are presented in section 3.5.

3.2 Aggregator and the Retailer Business Models

The retail and aggregation businesses are compared in this section. An abstraction of the business model canvas is used to describe the core business of each actor. Their business models are described in terms of value creation strategy, revenue model, customer segments and key partners of each party. First the retailer's business model is described. Second the aggregator's business model is presented. Third both businesses are compared in order to abstract similarities and differences.

[21] The internal workshops were held in Espoo, Finland (April 2018); Kranj, Slovenia (October 2018) and Brussels (November 2018) and attended by representatives of the 18 STORY project partners. The advisory board meeting was held in Kranj, Slovenia (October 2018) and was attended by 14 experts in the energy sector and 13 members of the STORY project. The 14 experts are mid to high level management executives belonging to the energy industry, industry associations, system operators, regulators, and academia.

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CANVAS BUILDING BLOCK	DESCRIPTION
VALUE PROPOSITION	The bundle of products and services that create value for a specific customer segment.
REVENUE STREAMS	The cash a company generates from each customer segment.
CUSTOMER SEGMENTS	The different groups of people or organizations an enterprise aims to reach and serve.
KEY PARTNERSHIPS	The network of suppliers and partners that make the business model work.

Table 7: Description of selected Canvas building blocks. Based on (Osterwalder et al., 2010)

A business model describes how a company plans to create value for its customers and capture a portion of the value it creates (Chesbrough & Rosenbloom, 2002; Osterwalder et al., 2010; Zott et al., 2011). Nine basic building blocks of a business model are identified: customer segments, value propositions, channels, customer relationships, revenue streams, key resources, key activities, key partnerships (Osterwalder et al., 2010). Four of these blocks have been chosen to compare the core business of the retailer and the aggregator in this paper: value proposition, revenue streams, customer segments, and key partnerships. Table 7 presents a summary of these building blocks as proposed by (Osterwalder et al., 2010).

The value proposition of a company is an aggregation, or bundle, of benefits that a company offers customers (Osterwalder et al., 2010). The revenue model, or value capture, reflects the value that each customer is truly willing to pay for. Customer segments are the different groups of people or organizations an enterprise aims to reach and serve. Key partnerships refer to the network of suppliers and partners of a company. The purpose of this paper is to compare business models, rather than to examine each in depth. It is estimated that the four blocks chosen explain the main similarities and differences that lead to conflict between the retailer and the aggregator.

The business model canvas framework has been previously applied in the energy sector, specifically for demand response and distributed technologies by (S. P. Burger & Luke, 2017), (S. Burger, Chaves-Ávila, Batlle, & Pérez-Arriaga, 2017), (Hall & Roelich, 2016). A key driver of investments is the viability of business models in the electricity sector (Blyth, McCarthy, & Gross, 2015). Both retailer and aggregator business models have been previously studied in literature. Business model innovation in supply (retail) markets is analysed in (Hall & Roelich, 2016; Richter, 2012a). The value of aggregators in energy markets is explored in (S. Burger et al., 2017; Lampropoulos et al., 2018).

Several applications of the business model framework in energy are related to the use of technology which could be integrated into the network by either an aggregator or a retailer. Using a business model framework business model archetypes are identified based on publicly available information from 144 companies offering three demand response categories: demand response and energy management systems, electrical and thermal storage, solar PV (S. P. Burger & Luke, 2017). An empirical study of two energy services company models illustrates how local authorities develop business models to create and capture value for better use of resources in (Bolton & Hannon, 2016). In a review of business models for renewable energies two basic distinctions are found: large scale

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utility side business models, and small customer-side business models (Richter, 2012b). A business model framework is used to analyse the potential of storage technologies in electricity markets (Mir Mohammadi Kooshknow & Davis, 2018).

A large part of business model studies found in literature apply to technology applications rather than the actors that will commercialize them. This paper aims to use the existing literature within the context of the specific intermediaries in the electricity market: the retailer and the aggregator. The value added is the comparison of both types of business. This comparison is then used to place both actors in the existing electricity markets and explain the conflicts and policy implications caused by their actions. This section explores the business models of a traditional retailer and an aggregator. While a retailer could also take on aggregator functions, they are described here as separate entities for the sake of clarity. Even when one entity would perform both retail and aggregation functions the roles they play and their value propositions differ as will be explained in this section. First, the business model of each, the aggregator and the retailer, is presented in terms of their value creation and value capture strategies. Second their intermediation role is analysed aiming to describe their relationship to both the consumer and the electricity markets. Annex 1 summarizes the evidence found in literature regarding the retailer's and aggregator's business model archetypes.

3.2.1 Retailer Business model

A retailer, also called a supplier, is an entity who buys energy from producers and resells it to final consumers (European Commission, 2016c; Steiner, 2000). Retailers act as intermediaries between the final consumer, the producers, and the electricity market day-ahead and intraday exchanges.

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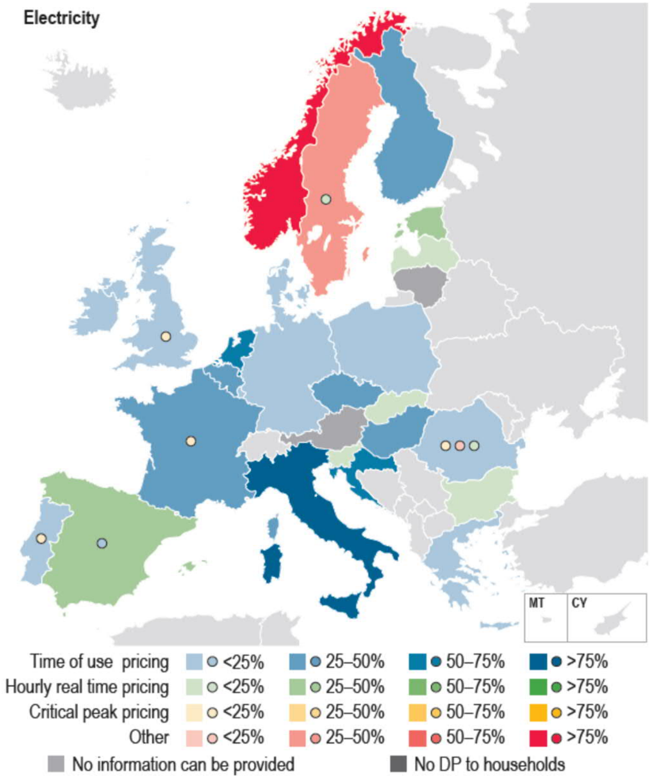

Figure 8: share of household consumers served by dynamic pricing for the supply and network charges in electricity in EU Member States -2015. (ACER & CEER, 2016b)

While consumers are free to choose which retailer to buy electricity from, they must have a contract with a fully licensed retailer in order to have access to electricity services. This section makes a distinction between the traditional retailer archetype and an innovative retailer archetype. First, the traditional retailer's business model is described based on their value proposition, revenue streams, customer segments and key partners. Second, retail innovation on value proposition and value capture is explored. The information presented on this section is based on available literature, statistics, and web site information of retailers.

The traditional retailer's value proposition relies on increasing kWh units sold to remain profitable, this archetype is called a throughput-based utility model (Hannon, Foxon, & Gale, 2013), (Hall & Roelich, 2016). In this model, the retailer acts as a dealer between consumers and generators. Its main responsibility is to make sure that he has procured enough generation to cover the demand of its consumers at any given time. The retailer, traditionally, also acts as the sole point of contact between the consumer and the rest of the electricity value chain. Grid costs in the form of tariffs as well as taxes and levies are included in a single bill presented to the final consumer. The retailer handles the billing process. The incumbent business model often misses opportunities for energy efficiency since demand reductions undermine profits under a throughput-based business model (Hall & Roelich, 2016). This business model encourages economies of scale as it is based on volume, and may lead to unsustainable practices (Unruh, 2002). A study depicting utility business model

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Electricity

MS	Number of countries	Years since liberalisation	Year	Average number of offers	Average number of offers per supplier	Percentage of spot-based offers	Percentage of green offers	Percentage of offers with additional services	Average switching rates
Group I	3	≤5	2015	1	1	0%	0%	0%	0.0%
			2013	1	1	0%	0%	0%	0.0%
Group II	17	5≤10	2015	↑33	↑2.7	↑3%	↓15%	↑9%	↑4.6%
			2014	23		0%	20%	7%	5.3%
			2013	20	2	0%	17%	2%	4.4%
Group III	9	>10	2015	↑191	↑3.4	↑10%	↑46%	↓7%	↑9.9%
			2014	181		8%	37%	8%	9.6%
			2013	127	2.8	7%	33%	10%	9.8%

Figure 9: Overview of selection of differentiating elements in electricity retail offers depending on the number of years since liberalization- Europe. Source (ACER & CEER, 2016b).

archetypes concludes that utilities are bound to their traditional way of business and lack business model innovation capabilities (Richter, 2013).

The retailer's revenue stream consists in capturing value directly from kWh sold to consumers by adding a mark up to energy sourcing costs (ACER & CEER, 2016b; Eurelectric, 2016; Hall & Roelich, 2016). The retailer bills consumers the price of its sourcing costs plus a mark up. Several types of billing programmes are available. The simplest one is flat pricing, where the consumer pays a single price per kWh for the duration of the contract. Other types of pricing have been introduced in order to differentiate the time when a consumer uses energy. According to (Stagnaro, 2017) retail value capture differentiates between time-of-use tariffs and time-invariant tariffs, fixed versus variable price offers, and possible permanent and temporary discounts given to consumers. Retail pricing schemes have been studied in literature (Borenstein, 2005; Duso & Szücs, 2017; Hu, Kim, Wang, & Byrne, 2015). Time-of-use tariffs charge consumers for blocks of peak or off-peak energy, usually day and night. The tariff varies throughout the day, but it is set as a fixed price offer in the contract that the consumer signs. Critical peak pricing can be combined with either flat or time-of-use pricing, it uses real-time pricing at times of an extreme system peak and is restricted to a small amount of hours per year. Real-time pricing varies hourly for a consumer depending on spot-price conditions of electricity exchanges. Figure 8 shows the share of household consumers that are under a dynamic pricing scheme in EU Member states as of 2015 (ACER & CEER, 2016b). Only Norway and Sweden use spot-based pricing based on monthly spot-exchange prices at a penetration of 25-50% in Sweden and over 75% in Norway. Time of use pricing is the second prevailing pricing scheme paid by over 50% of households in France, Belgium, Czech Republic, Croatia and Romania. Metering capabilities of retailers affect which pricing they can offer to their consumers.

Additional services that household consumers sign up for include home accidental damage insurance, loyalty programmes, discounts for direct energy payments, price caps, fuel source specifications, and dedicated web services. Non-price-related energy offers to consumers contain the following elements (ACER & CEER, 2016): Energy source (fossil versus renewable), type of fuel

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(electricity only, gas only, or dual-fuel offers), additional services provided by the supplier to attract consumers (meter reading, insurance services, maintenance, supermarket points, gifts, etc...), contract duration. Figure 9 presents an overview of the differentiating offers that consumers receive from retailers in European countries based on years since liberalization. Fixed price offers account for the majority of all electricity retail offers in Europe. Spot based price offers account for only 10% of all offers in the highest case, countries with more than 10 years of liberalization in 2015. Green offers range from 15% to 46% of offers in countries with 5 to 10 years of liberalization. In 12 out of 20 capital cities in Europe, fixed price offers, which are assumed to include a risk premium, are lower than variable prices (ACER & CEER, 2016b).

Little attention has been given in literature about business models to customer segments that retailers must service. This is probably because every electricity consumer must purchase energy through a retailer, therefore they serve all types of consumers. That being said, electricity price data is reported based on consumption bands where a household consumes between 2,500- 5,000 kWh, a medium size company consumes between 500 MWh-2,000 MWh, and an industrial consumer consumes between 20,000 MWh- 70,000 MWh (ACER & CEER, 2018b)(Eurostat, 2018). A retailer needs to have an accurate forecast of the consumption profiles of the different types of consumers it services. Contracts and negotiations are also more detailed for larger consumers. In addition to final consumers, retailers also trade energy among each other in the day-ahead and real time markets either directly or through a Balance Responsible Party. Similarly, a retailer may act as a balancing service provider towards the system operator when vertically integrated with generation.

As mentioned earlier the key value that a retailer proposes to consumers is availability of electricity at all hours. Meaning that consumers are free to consume as much electricity as their connection capacity allows at any given moment. In order to provide this service reliably a retailer enters into long term contracts with generators to cover a large part of their expected forecast. Thus, a key partner of retailers are large utilities through long term power purchase agreements (Richter, 2012b). New entrant generation wishes to lock in prices for up to 15 years, while new entrant supply businesses wish to do so for up to 2 years (Economic Consulting Associates, 2015). It is estimated that most electricity consumption is contracted in forward markets and bilateral markets. Estimated total volumes traded in forward markets have a churn ratio ranging from 1 to 11 times the physical consumption (ACER & CEER, 2018a). Intraday volumes represent less than 15% of electricity demand in European countries (ACER & CEER, 2018a). Exchange platforms serve to buy short term differences to cover contract positions and are also key partners of a retailer. In addition, a retailer has balancing responsibility towards the network operator in its area. The retailer has a responsibility to match electricity bought to electricity sold on a real-time basis. In order to achieve this, a retailer must either be a licensed balancing responsible party or participate in the market through one. When the retailer cannot match supply to demand, it incurs an imbalance and is liable to be penalised. Therefore the balancing responsible party, and the system operator are also key partners of a retailer. The relationship between the retailer, the balancing responsible party and the system operator will be explained in more detail in section 3.3.

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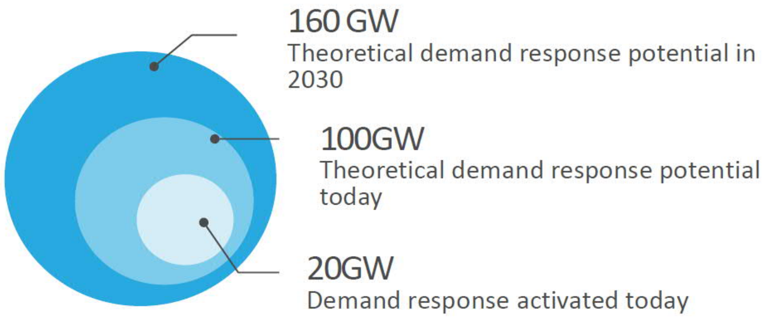

Figure 10: Demand response potential in Europe (European Commission 2016)

Business model innovation for retailers presents, in addition to the traditional value model, other sources of value for consumers such as energy source differentiation, bundled services, re-localizing energy value and efficient provision of energy services. Energy source differentiation refers to the sale of energy purchased exclusively from renewable energy producers (Stagnaro, 2017). Another innovation in retail points to the energy services company (ESCO) model, which aims for an efficient provision of energy services as opposed to units delivered (Bolton & Hannon, 2016). In addition a retailer can re-localize energy value in the form of a municipal services company or cooperative (Hall & Roelich, 2016). In this case, the retailer favours purchases from local energy producers such as neighbourhood photovoltaic, small wind turbines, CHPs, biomass, and other small distributed units. An example, in Belgium, is Ecopower who offers consumers the choice to buy green energy once they become cooperative members (Ecopower cbva, 2018). As such, consumers co-own the production assets of Ecopower and are entitled to dividends in case of revenue. In addition to electricity Ecopower also sells biomass for heating purposes in the form of pellets and recycled wood bricks. NLE, a company in the Netherlands, offers bundled contracts so that consumers pay one single bill for electricity, internet, phone, TV and car leasing (NLE, 2018).

In conclusion, innovation in the purely retail business' value proposition lies in three main aspects: 1) Mixed offers allowing fixed or variable prices, 2) Differentiating energy sources (fuel or renewable) and 3) Offering additional services to consumers. In all these propositions, however, the core value capture of a throughput-based model remains. Research innovation in retail business models points towards the aggregation role, active involvement in local energy communities, and enabling direct peer-to-peer trading. However, the statistics presented evidence that most consumers are still served through fixed price contracts, and additional value offers are likewise limited. Innovative electricity retail proposals exist, but they are not representative of the retail business at large.

3.2.2 Aggregator Business Model

Aggregators have come to fill the gap left by the traditional retailers' top down approach. Consumers slowly become able to participate in energy markets through explicit demand response. It is estimated that only about 20% of the demand response potential is activated today as can be seen in (European Comission, 2016). An aggregator is a service provider who operates – directly or indirectly – a set of demand facilities in order to sell the flexibility available from pools of electric loads as single units in electricity markets (SEDC, 2017). Other definitions of aggregator exist; in

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the clean energy package of the European Commission the aggregator is defined as a market participant that combines multiple customer loads or generated electricity for sale, for purchase or auction in any organised energy market (European Commission, 2016c). This section builds an aggregator business model archetype built based on available literature and complemented by a series of interviews and workshops held within the STORY H2020 project[22], and an advisory board workshop of the project[23] involving energy sector professionals and project developers. In order to study the aggregation business this section first introduces the need for an aggregation role. Second the aggregator's business model is studied through the building blocks introduced earlier: value proposition, revenue model, customer segments, and key partners.

The aggregation role is necessary to enable access to electricity markets for small consumers who do not have the volume, the knowledge or the will to participate in the existing markets. The aggregator, similar to the retailer, is an intermediary between the final consumer and the electricity markets. In the impact assessment accompanying the proposal for a directive on common rules for the internal energy market in electricity the commission states that households and businesses often have scarce knowledge and little or no incentive to change the amount of electricity they use or produce in response to changing prices in the market' (European Comission, 2016). Participation in electricity markets requires minimum volumes of entry, ranging from 0.1 MWh to 1 MWh or even 5MWh at a time (SEDC, 2017). Household consumers can offer at most between 5-10 KWh at a given moment depending on their installed technologies and consumption needs. An aggregator is a middleman necessary to group the offers of small and medium consumers in order to reach the required market volumes. Electricity markets also have complex requirements to be able to trade in them. Market participants must comply with balancing responsibility, provide bank guarantees and obtain licenses to be able to buy and sell electricity. These requirements represent high average fixed costs of participation in electricity markets.

The aggregator's value proposition lies in managing and pooling flexibility provided by either demand, storage, or distributed generation . An aggregator contracts with small consumers or distributed generators, defines their flexibility potential and installs required metering and communications equipment. The aggregator holds information in real time about when and how much consumers can shift their expected load profiles. The aggregator then pools its portfolio of

[22] The project is called added value of Storage in distribution systems, referred to as STORY H2020 project. The project consists of 8 demonstration cases with local/ small-scale storage concepts and technologies covering industrial and residential environments. The project is comprised of 18 partners in 8 countries all over Europe. For more information visit http://horizon2020-story.eu/

[23] Semi structured interviews were made to project developers who seek to use demand response flexibility. All six STORY demo leaders were interviewed. In addition, three more project developers were interviewed, two in the UK, and one in Germany, their identities are not disclosed to protect their privacy. The three internal workshops mentioned consisted of defining the business model canvas for each demo within the project, representatives or STORY H2020 partners were present at each session, including an aggregator, demo leaders and technology providers. The advisory board workshop was held in Slovenia in October 2018, it consisted of 14 professionals in the energy sector invited to provide their opinion on business models for storage, and related technologies. Though the focus of the STORY 2020 project is the integration of storage into distribution systems, it was apparent in the workshops that the business models are broader than a single technology, and depend on having access to the available ecosystem. Therefore selected results where aggregators and retailers are involved are presented in this paper.

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flexibility to make an offer to sell flexibility in the energy markets. The fundamental value of aggregation is capturing economies of scale and scope due to the existence of high fixed costs of participation in electricity markets (S. Burger et al., 2017). The aggregator acts as an energy service provider with a customer side business model (Richter, 2012b). It also provides better routes to market for local generation, and a mechanism to fulfil the potential of the demand side (Hall & Roelich, 2016). Part of their business proposition is offering customized solutions and energy services (Richter, 2013). The aggregator's value proposition is divided among different participants in the value chain: consumers, market participants and system operators. The value of aggregation for final consumers lies in a smart management of their home technology and demand profile. Aggregators are also acting as technology providers, installing better metering, smart home management systems, and communication technologies (S. P. Burger & Luke, 2017; STORY H2020, 2018). The benefit that final consumers perceive depends on the contract between the aggregator and the consumer. Final consumers expect to see savings in their electricity bill, and perhaps even receive an additional incentive from the aggregator to change their consumption patterns. Savings on the electricity bill and revenue sharing have been identified as value propositions of aggregators (STORY H2020, 2018; STORY H2020 Advisory Board Workshop, 2018). Market participants such as generators and retailers may benefit from aggregation as they have access to cheaper sources of flexibility that they can use for hedging forecasting errors or large deviations in renewable energy. For example, instead of activating a pricey oil fuelled generator a market participant might buy flexibility from an aggregator for a cheaper price. In a similar manner, system operators can activate flexibility from demand side resources for system balancing. It is found that demand response and energy management businesses are already participating in balancing markets, offering firm capacity, operating reserves, constraint management, and secondary frequency control (S. P. Burger & Luke, 2017). In such a scheme, resources are aggregated and certified to meet the balancing technological requirements. In summary, aggregators, propose values that are difficult to capture in the short term such as consumer empowerment, and better use of local resources (STORY H2020, 2018; STORY H2020 Advisory Board Workshop, 2018).

Just as the value proposition of the aggregator is divided among several market agents, their revenue streams also come from different agents. Aggregators capture value from final consumers through their roles of technology provision, smart energy management, and brokers. As technology providers aggregators earn income from technology sales or leases. As smart management agents aggregators earn income from consumers in the form of subscription fees (STORY H2020 Advisory Board Workshop, 2018). As brokers enabling access to markets aggregators earn income in the form of brokerage fees (S. P. Burger & Luke, 2017). Aggregators generate income from other market participants through commodity sales, an aggregator trades flexibility from its pool of available resources. In balancing markets aggregators are paid for different balancing services as mentioned above, according to each market's payment rules. Reserves may be paid for both availability and energy actually dispatched.

The customer segments of an aggregator can be derived from the previous discussions: final energy consumers, distributed generators, wholesale market participants, TSOs and DSOs. An aggregator serves final energy consumers at both household and industrial levels. An aggregator may also provide services to small distributed generators. The aggregator resells their flexibility to wholesale

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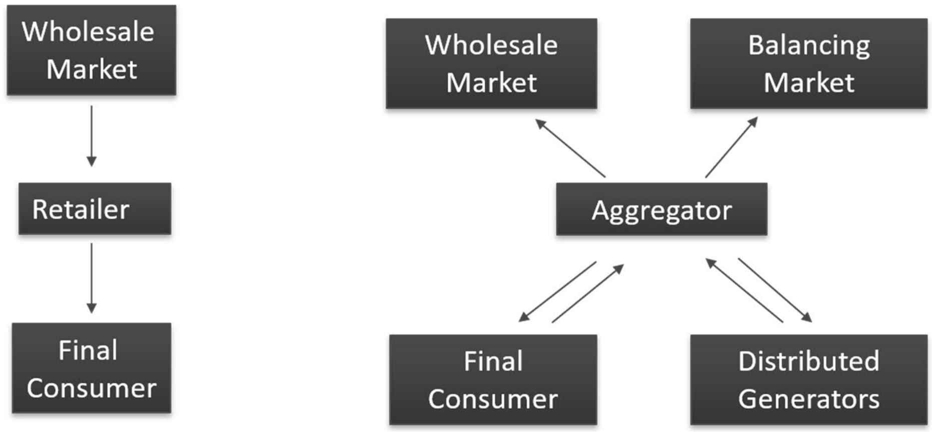

Figure 11: Visualization of retailer and aggregator business model configurations

market participants, who can be retailers or generators. System operators at transmission and distribution level may also be customers of an aggregator who buy balancing services. Since the aggregator has customers on both the retail and the wholesale sides of the market it can be considered to be a platform-type of intermediary.

The key partners of an aggregator are the same as its consumers, as well as the retailer of those consumers, spot exchange platforms and technology providers. It has been shown before that aggregators have complex relationships with their customers. In addition to being customers, they are also service providers, and in the case of the system operators they are enablers. The aggregator needs to have good relationships with grid operators to know when services are necessary and possible. System operators need to signal market participants when the system does not allow certain transactions to occur. Aggregators could also provide access to final consumers to spot exchange platforms. Technology providers become increasingly important to harvest flexibility from consumers. Measurement and communication equipment, electrical and heat storage, as well as system interoperability are essential for an aggregator to deliver flexibility.
The aggregator's business model revolves around its capability to create a demand flexibility profile and sell it at the appropriate moment. The aggregator is an intermediary who adds value by bridging the gap between small consumers and the larger electricity market. Without an aggregator household consumers do not have the capability, the access, nor the critical mass needed to participate in the electricity markets. The aggregator's business model can be classified as a multi-sided platform bringing together two or more distinct but interdependent groups of customers (Osterwalder et al., 2010). A platform has value for one group of consumers only when the other groups are present in sufficient numbers, thus having a network effect (Belleflamme & Peitz, 2010).

3.2.3 Retail and Aggregator Business Model Comparison

There are two main differences between the retailer and the aggregator business model archetypes. The first is how they make their core profits, either from a mark-up in energy prices or price arbitrage close to real time. The second is the nature of their intermediation role, where the retailer acts as a dealer and the aggregator as a platform. Two case studies are used in this section to

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illustrate the role differences between the two actors. The business model framework described above is applied to the cases, presented in Annex 2.

First, the difference in how each actor makes profits is explained. Retailers profit from the prices spread, or mark-up, between the wholesale and the retail electricity price. While the aggregator's profit lies in price arbitrage in the wholesale market and the value of reserves. Retailers procure energy on a long-term basis and rely on the fact that consumer's loads are predictable and relatively inelastic, while aggregators seek to make demand more elastic and make a profit from it. It's been noted earlier that retailers have a responsibility to provide energy to consumers, up to a consumer's connection capacity, at all times. Aggregators create value when consumers deviate from their expected consumption profiles. Case study 1, in Annex 2, presents an aggregator who installs an interoperable technology system across 13 houses in a rural neighbourhood in Belgium. The aggregator creates value for consumers by optimizing their energy consumption to propose energy services. Nevertheless the aggregator only captures value from a subscription fee to be paid by consumers, and from technology installation and management. At the point of this writing, the aggregator didn't consider it profitable to sell that energy in the balancing markets where it participate due to the small scale of the pilot project. The consumers continue paying their energy supply bills to the retailers that they used before the project.

The second difference is how they structure their intermediation role towards the wholesale and balancing markets. Both the aggregator and the retailer play a role of intermediation between the final consumer and the electricity markets. The retailer buys energy either directly from generators or from a market exchange and sells it to consumers. While the aggregator pools flexibility from consumers in order to sell it to either the wholesale market in day-ahead or real time, or the balancing market. Their role as intermediaries is different, the retailer is a dealer while the aggregator is a platform between a pool of consumers and the buyers of flexibility in different the energy markets. This relationship is visualized in Figure 11, where the direction of the arrows represent who is selling services to whom. The traditional retailer acts as a dealer, buying from a wholesale seller and selling to a retail customer. The profit of the retailer is the mark-up between the buying price and the selling price, or the price at which the retailer buys from generation and sells to consumers. The aggregator in the meantime serves as a platform to match consumers that can offer flexibility at appropriate times and market participants who need that flexibility for balancing. The aggregator sells technology and services to consumers and in turn buys their flexibility to resell in the wholesale & balancing markets. In fact, the aggregator holds enough knowledge of both its consumers and the wholesale markets to know when flexibility is available and has a value. Case study 2, in Annex 2, illustrates a company who is installing a Compressed Air Energy Storage unit to provide flexibility in the form of generation or load on demand. The company needs to contract with a retailer to be able to buy energy and needs to contract through an aggregator to be able to sell energy. The company seeks to participate in several electricity markets, but their unit is not large enough to meet the 4MW minimum participation requirement.

In summary, the retailer as a figure could also provide aggregation services, and serve as both a retailer and an aggregator. However, in order to do so a retailer needs to change core aspects of its business model and move from being a dealer to being a platform. This change requires an

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extension of capabilities in terms of technology, information, contracting and knowledge management. The fact that demand response is already active and remunerated in balancing markets across Europe indicates that markets have a need to reap flexibility from end users. Independent aggregators have come to fill that need, but their appearance in the market causes conflicts with retailers and other market parties. An independent aggregator comes to modify load profiles that a retailer has already procured energy for in the long term markets. The conflicts that arise in practice are studied next.

3.3 Conflict between roles of retailer and aggregator in the electricity market

A conflict arises between the aggregator and the retailer when the former would, in real-time, modify the consumption profile of the retailer's customers. As mentioned earlier, the retailer fulfils its responsibility when the energy it buys in bulk matches the retail energy it sells to final consumers. Actions of a third party aggregator may cause imbalances for the retailer. This section aims to shed light on the interaction and conflicts between the retailer, the aggregator, and the balancing responsible party. First, the aggregator-retailer interaction is described in order to clarify why and when they enter into a conflict when the aggregator dispatches demand response. Second, the relationship between the aggregator and the balancing responsible is explored. This is done because the retailer either is a balancing responsible party or has a contractual relationship with one. The latter will represent the retailer towards the TSO and is responsible for balancing.

3.3.1 Aggregator-Retailer interaction

The aggregator's interaction with the retailer is described in this section. A problem arises because the aggregator is activating demand response flexibility from consumers who already have contracts with a retailer. The conflict is economic in nature as the aggregator causes an open position to the retailer. First, the setting without an aggregator is explained. Second the situation when an aggregator enters the market is compared to the setting without an aggregator. Third, the controversy that arises between the aggregator and the retailer is explained. Finally the implications of the open position caused by the aggregator are discussed.

First, the situation without an aggregator is described. The retailer has an established contractual relationship with a final consumer. Under a typical retail contract the consumer subscribes to a certain tariff, which could be either fixed or dynamic. The consumer is then free to consume any amount of energy from 0 kWh up to her connection capacity. The retailer is responsible for procuring energy for the final consumer in the wholesale market. The retailer forecasts the expected consumption of its portfolio of consumers and it is responsible for any errors in forecasting.

Second, the situation when an aggregator enters into a contract with the consumer is described. When an aggregator enters the picture the consumer agrees to sell flexibility to the aggregator. Flexibility is defined as the modification of generation injection and/or consumption patterns in reaction to an external signal (EURELECTRIC, 2014). The consumer and the aggregator establish a baseline together, meaning an expected consumption profile. Flexibility is then calculated as deliberate deviations from that consumption profile. The aggregator and the consumer agree

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together on terms for the activation of flexibility. In practice, demand response is mostly discussed as a demand reduction in electricity consumption; even though it could also be a demand increase. Retailers have an obligation-to-serve which entitles consumers to a volumetric call option for the right to buy electricity (H. P. Chao, 2010). When they enter a contract with an aggregator consumers agree to forego their right to use as much energy as they would like to, within the limit of their connection capacity, and can sell energy deviations with respect to their baseline.

Third, the controversy between the retailer and the aggregator is explained. A problem arises when the final consumer changes her consumption at the request of the aggregator. The retailer had forecasted and procured a certain amount of energy for the final consumer. If a demand response request is activated, and the retailer is not aware of it, the estimated load, and energy procured, will be mistaken. The retailer then faces an open position since it has to either be balanced, or contract balancing services through a balancing responsible party. When the aggregator activates downward demand response the retailer procures more energy than will be consumed and therefore faces a long position. When the aggregator activates upward demand response the retailer procures less energy than needed and thus faces a short position.

In conclusion, given that the nature of this conflict is economic in nature, who is responsible for covering the open position of the retailer? Up until now accurate forecasting has been the responsibility of the retailer. Any deviations from the forecast are a risk inherent to the retailer's business. Now deviations are caused on purpose by a third party, the aggregator. The retailer claims that the aggregator should compensate the cost of the energy procured and not used. This means that the retailer is laying a claim on the load forecasts of its consumers. This claim would only be valid if the consumer had contractually agreed to stick to a certain load curve. Even in this case, the contractual relationship lies between the consumer and the retailer. The aggregator contracts with the consumer, and has no legal obligations toward the retailer. The question remains, though, whether it is in the best interest for the system to have a party who systemically causes open positions on another party.

3.3.2 Aggregator-BRP interaction

The conflict between the aggregator and the retailer's BRP is an extension of the conflict with the retailer. First, in order to study the interaction between the aggregator and the retailer's BRP the concept of balance responsible party is explained. Second, the relationship between the retailer and its corresponding BRP is explained. Third, the imbalance pricing rules that a BRP faces towards a TSO are explained. Fourth, the consequences for the BRP of facing the imbalance pricing are discussed. Fourth, a conclusion is drawn about the uncertainty around the conflict between the aggregator, the retailer and the BRP.

First, the concept of balance responsible party is explained. Balancing means that energy offtake will be equal to energy injected. BRPs are defined in the CEP proposal for a regulation on the internal market as 'a market participant or its chosen representative responsible for its imbalances in the electricity market'. The final position of a balance responsible party can be calculated by one of the following three approaches, as stated in the network code for balancing in article 54(3) (European Commission, 2017b):

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	Imbalance price positive	Imbalance price negative
Positive imbalance	Payment from TSO to BRP	Payment from BRP to TSO
Negative imbalance	Payment from BRP to TSO	Payment from TSO to BRP

Table 8: Imbalance price and payment as determined by the TSO

BRP's Situation due to Demand Response	Upward demand response	Downward demand response
BRP's position	Negative imbalance (short)	Positive imbalance (long)
BRP's imbalance payment	Negative when the imbalance price set by TSO is positive. (BRP pays TSO)	Positive when the imbalance price set by TSO is positive. (TSO pays BRP)

Table 9: BRP's situation due to demand response activation

a) Balance responsible party has one single final position equal to the sum of its external commercial trade schedules and internal commercial trade schedules.
b) Balance responsible party has two final positions: the first is equal to the sum of its external commercial trade schedules and internal commercial trade schedules from generation, the second is equal to the sum of its external commercial trade schedules and internal commercial trade schedules from consumption.
c) In a central dispatching model, a balance responsible party can have several final positions per imbalance area equal to generation schedules of power generating facilities or consumption schedules of demand facilities.

Second, the relationship between a retailer and its BRP is explained. Every retailer is dictated to either be a Balance Responsible Party itself, or enter into a contract with one. A BRP may transfer all the risk of open positions to the retailer, acting only as an intermediary between the retailer and the TSO. In this instance, the situation depends upon the risk sharing contract between a retailer and its BRP, assuming that they are different entities. Or, a BRP may be a decision making entity balancing a portfolio of retail and generation in order to hedge risk.

Third, the imbalance pricing rules that a BRP faces toward the TSO are explained. The rules for balancing are outlined in the network code on electricity balancing. An imbalance means 'an energy volume calculated for a balance responsible party and representing the difference between the allocated volume attributed to that balance responsible party and the final position of that balance responsible party, including any imbalance adjustment applied to that balance responsible party, within a given imbalance settlement period' (European Commission, 2017b). The allocated volume is 'an energy volume physically injected or withdrawn from the system and attributed to a balancing responsible party, for the calculation of the imbalance of that balance responsible party'. The final position of a balance responsible party is 'the declared energy volume of a balance responsible party used for the calculation of its imbalance.' In article 54 the EB defines that 'allocated volume shall not be calculated for a balance responsible party which does not cover injections or withdrawals.'

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The imbalance adjustment is defined in article 2 as ‘an energy volume representing the balancing energy from a balancing service provider and applied by the connecting TSO for an imbalance settlement period to the concerned balance responsible parties, used for the calculation of the imbalance of these balance responsible parties’ (European Commission, 2017b). An imbalance price is determined by the TSO, and the imbalance payment is made as defined in article 55 and presented in Table 8. In article 54(6) it is dictated that ‘an imbalance shall indicate the size and direction of the settlement transaction between the balance responsible party and the TSO; an imbalance can have alternatively:

a) A negative sign, indicating a balance responsible party’s shortage;
b) A positive sign, indicating a balance responsible party’s surplus.’ (European Commission, 2017b).

Third, the imbalance position caused to the BRP by the aggregator’s actions is explained as presented in Table 9. It follows the same logic as for the retailer, except that this time it represents the position towards the TSO as generation and consumption schedules are submitted. The BRP has a negative imbalance, meaning a short position, when upward demand response occurs. In contrast, the BRP has a positive imbalance, meaning a long position, in a downward demand response event. The BRP is liable towards the TSO, and will therefore face imbalance payments which can vary depending on the imbalance method used in each country. In a dual imbalance payment system, the BRP has to pay the TSO for a short position, but receives money for a long position (if the long position is helping the system). The imbalance prices set by the TSO, can be negative or positive, depending on the direction of the whole system imbalance and the actions that are needed to correct it. Imbalance prices on both directions may be equal under a single imbalance price system, or different to each other under a dual imbalance system (Vandezande, Meeus, Belmans, Saguan, & Glachant, 2010). It can be concluded then, that the imbalance caused by the aggregator may cause either a loss or a profit for the BRP depending on the direction of the imbalance and the system’s position.

It is still uncertain what the best way to solve the controversy around the aggregator, the retailer and the BRP is. The issue about whether the aggregator should pay a compensation- also called a transfer of energy payment- and to whom is still open. The following section introduces policy and current practices in selected European countries.

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3.4 Policy and current practice

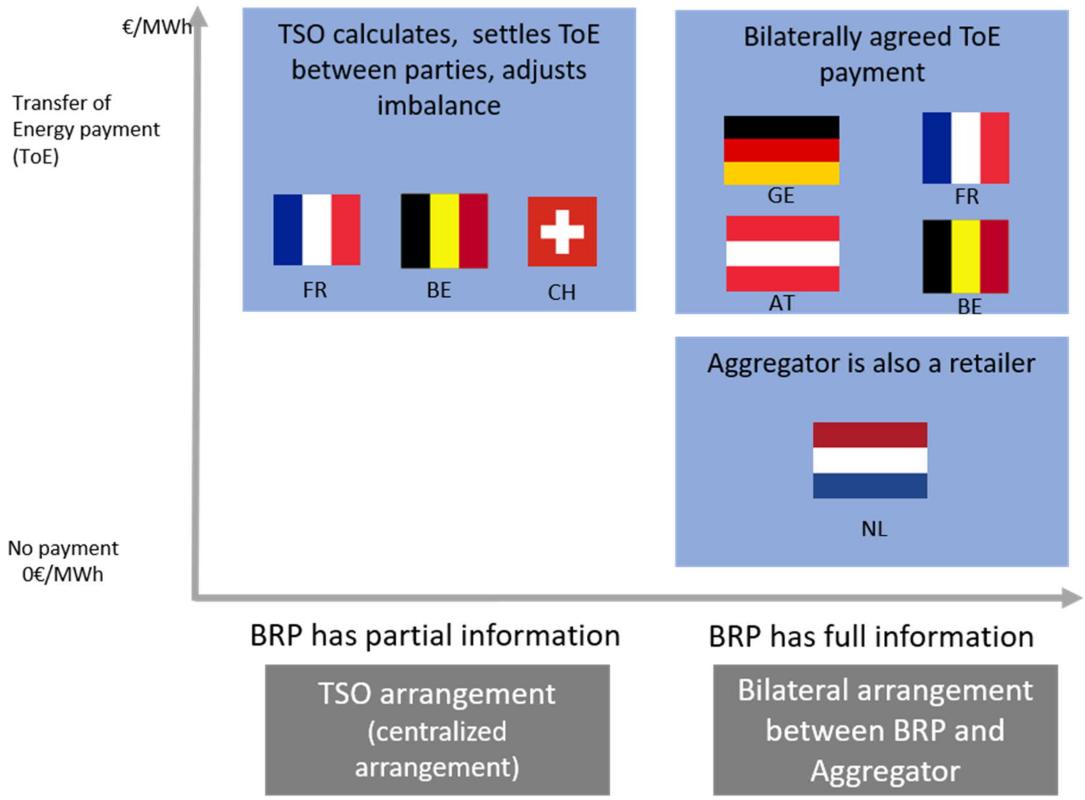

Figure 12: Current practices: retailer-BRP-aggregator relationships

There are currently four main ways of dealing with the compensation controversy. They revolve around a) whether the aggregator needs to make compensation (or Transfer of Energy) payment to the BRP and b) whether the BRP has information about the contract of the aggregator and the consumer supplying demand response. Based on these two criteria three main configurations are currently in place in selected countries around Europe as can be observed in Figure 12: a)TSO calculates and settles transfer of energy payment between parties and adjusts imbalance; b) bilaterally agreed compensation between the independent aggregator and the BRP; c) The aggregator is also a retailer. This section first discusses the two main issues that dictate the three configurations presented above. Second, current practices in each configuration for selected representative countries are explored.

First the issue about how much information a BRP has over the aggregator's contract, and the compensation payment are explained. If the retailer knows about the aggregator's contract with a final consumer, then the retailer can adjust its supply profile accordingly. This means that the aggregator needs the consent of the retailer in order to engage in a demand response contract with a final consumer. In this case, the conflict is solved contractually before demand response takes place as the retailer can integrate the expected demand response into its load forecast thus avoiding open positions in the market. Nevertheless, the retailer's business model relies on increasing kWh

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units sold to the final consumer. In a peak pricing scheme the retailer may lose profit if the aggregator shaves demand peaks by transferring peak demand to valley hours. The retailer may have an incentive to block the aggregator's contract, or even propose a counter offer for demand response to its own consumer.

Second, current practices as grouped in Figure 12 are described and country examples are presented:

a) TSO calculates and settles transfer of energy payment between parties and adjusts imbalance.

In this scheme the TSO acts as a clearing house, both verifying that demand response took place and making the necessary financial exchanges among the aggregator and the BRP. This mechanism eliminates conflict of interest regarding information exchange between the BRP and the aggregator. On the downside, it requires complex mechanisms and rules set by the TSO, adding to the responsibilities of the TSO. Under this mechanism the imbalance caused to the BRP by the aggregator is adjusted by the TSO. Meaning that the BRP is not liable for the imbalance caused. Examples of this mechanism are currently applied in Switzerland, France, and Belgium.

Switzerland: Balance Service Providers offering ancillary services to Swissgrid can aggregate loads form anywhere in the country without the agreement of the customer's BRPs (Swissgrid Ltd., 2018b). Swissgrid adjusts the imbalance, meaning that neither the BRP nor the BSP are charged for the imbalance caused due to demand response. According to the framework agreement on aggregated loads, the added value caused by the provision of balancing services, is handed to the aggregator. The aggregator is obliged to compensate the BRP 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).

France: In France, both energy and reserves markets are open to demand response. At the moment, only downward demand response is valorised. The NEBEF mechanism allows demand response to participate in the energy market. Independent aggregators are recognized, and a payment has to be made from the independent aggregator to the supplier. The payment is equivalent to the energy block transferred from the perimeter of the BRP to the aggregator for resale in the market. France enables several contractual models, settlement through a mechanism enabled by the TSO is one of them. Depending on the type of consumer providing demand response the payment can be performed by the consumer to the retailer through the 'corrected model' or by the independent regulator through the TSO 'regulated model'. Bilateral settlement is also allowed if the two parties wish to do so under the 'contractual model' (Pentalateral Forum, 2017; Rèseau de Transport d'électricité, 2018; SEDC, 2017).

Belgium: A transfer of energy payment applies for the manual FRR and will be implemented in the automatic FRR. The aggregator providing flexibility in the reserves markets makes a transfer of energy payment to the supplier of the customer who provides demand response (Elia System Operator, 2018b, 2018a). The payment is made on either a bilaterally agreed price, or in absence of an agreement, the regulator has determined a regulated transfer price (CREG, 2018). The

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aggregator, therefore, compensates the supplier for energy sourced but not invoiced due to the activation of upward reserves (equivalent to a drop in demand). At the same time, ELIA the TSO corrects the balancing perimeter of the supplier's BRP so that it will not be negatively affected by the activation of demand response. The aggregator's BRP is balance responsible for the difference between the delivered volume and the requested volume of flexibility. Balancing service providers are compensated for capacity and energy under a pay as bid method.

b) Bilaterally agreed transfer of energy payment:

In this scheme the aggregator and the BRP have a contractual relationship established before the delivery of demand response energy. This relationship clearly defines the compensation, or transfer of energy payment, that the aggregator needs to pay to the BRP for every unit of demand response dispatched. The upside of this scheme is that the aggregator's right to sell end-consumer flexibility is contractually recognized and clear terms are set. The downside is that a retailer might decide to offer similar services to the same consumers, effectively blocking an independent aggregator from entering the market. The examples of Germany and Austria, are presented next. Belgium and France are included in the same box in Figure 12 because they also accept a bilateral agreement between both parties.

Germany: The relationship between the consumer and supplier is regulated in Germany (Bundesnetzagentur, 2017a). The consumer will pay a baseline to the supplier. In times of downward demand response the consumer pays the cost of retail energy to the supplier (Bundesnetzagentur, 2017b). This payment is made for energy only, while tariffs and levies are charged only for metered energy. An aggregator must be a licensed supplier or has to work with one. The aggregator requires the retailer's agreement before offering demand based flexibility to the market. Both the aggregator and the retailer must be balance responsible parties in order to participate in the market. The baseline is established based on the previous 15 minutes to a demand response event; it is assumed that parties consume or generate the same amount of energy as in the last quarter hour before the polling period. The decision mentioned above applies only to the provision of secondary control power and minute reserve with a technical unit. The consumer must notify the supplier 6 weeks in advance when he wants to provide secondary control. An aggregator must have a contract with the consumer, the retailer, the TSO, and the DSO where applicable, in order to offer demand response services (SEDC 2017).

Austria: Similar to Germany, an aggregator requires a bilateral agreement with the BRP and must compensate it for its sourcing costs. Aggregators must also negotiate with their BRP concerning consumer data, curtailed volumes and money exchange.

c) Retailer/BRP is the Aggregator:

In this proposed scheme the aggregator is also the retailer of the consumer. The compensation controversy in this case does not exist since the consumer has one contract with the retailer who can then also offer demand response. This scheme has the upside of being straight forward and not needing further contracts or compensation mechanisms. On the downside the market is then closed to new entrants, such as independent aggregators, who might not yet have a portfolio of consumers.

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The case of The Netherlands is discussed next as a country where aggregators must also be suppliers in order to participate in the market.

The Netherlands: in order to offer aggregated demand response services, a party must become a retailer and either be a BRP or participate through a BRP (SEDC, 2017). However, multiple suppliers are allowed in the same connection. For example, energy for the house could be delivered by one supplier while energy for an electric vehicle is delivered by another supplier. Each supplier should have a smart meter and is balance responsible for the energy delivered. Consumers are able to choose what supplier to work with. Therefore, there is no need for a transfer of energy payment or a baseline.

3.5 Conclusion and Policy Implications

The relationship between an aggregator and a retailer poses policy implications regarding two main aspects: 1/ the level of the transfer of energy payment to be paid by the aggregator to a retailer or a BRP 2/ the amount of information the aggregator has to share with a customer's BRP in order to do aggregation. In this section, first, these two aspects are discussed in relation to the legislative proposal accepted by the council in the Clean Energy Package. Second, the role of intermediaries in consumer empowerment is highlighted. Finally, a look towards the future of a consumer-centric energy system concludes this study.

Current practices shown above favour the transfer-of-energy payment to the retailer. Article 17 of the CEP proposes that 'Member States may require electricity undertakings or participating final customers to pay compensation to other market participants or their balancing responsible party that are directly affected by demand response activation. Such payments shall not create a barrier for market entry of market participants engaged in aggregation or a barrier for flexibility. In such cases the compensation payment shall be strictly limited to cover the resulting costs incurred by the suppliers of participating customers or their balance responsible party during activation of demand response'. Retailers participate in the electricity market and are responsible for supplying energy to their final consumers. Balancing responsible parties are liable for imbalances in their schedule with respect to TSOs. This compensation or transfer of energy payment is relevant because it defines the price of demand response flexibility. It is expected that there will be more demand response in the market if it is adequately remunerated for its value to the system operator and other market participants. Thus, the setting of a compensation price directly affects the growth of the demand response market. The consumer's right to consume or stop consuming is being sold as a commodity. Policy needs to be established to clarify the legal relationships and claims on the flexibility of a consumer. It is up to policy makers to decide whether to favour aggregators in order to push forward the demand response market. If a compensation is deemed to be necessary, further study is needed on whether a centralized or a bilateral clearing mechanism is optimal. An empirical analysis of the impact of compensation on the retailer's and aggregator's profits would shed light on the trade-offs between different options.

The amount of information that the aggregator has to share with a retailer or BRP in order to perform demand response is also a key policy issue. In the current Clean Energy Package proposal for a directive it is stated in Article 17 that member states should include in their regulatory

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framework: ‘the right for each market participant engaged in aggregation, including independent aggregators, to enter electricity markets without consent from other market participants’. This is not the case in current practices, though, as can be observed in Figure 12: the countries where aggregation is allowed and does not depend on the consent of retailers are a minority. In any case, the BRP has access to at least partial information regarding the aggregator’s contracts with consumers in its perimeter. In the opposite case, when consent is not required the role of the system operator becomes larger. A platform type of arrangement is necessary when anonymity needs to be preserved.

If consumer empowerment is to become a reality consumers need to have access to electricity markets. Currently, only very large consumers have direct access to markets, all other consumers must contract with an intermediary to cover their energy needs. This paper illustrated the current roles of the intermediaries active today between markets and consumers: the retailer and the aggregator. It was shown that their core business models show opposing trends in value proposition and value capture. What is more there is no clear way yet to solve the balancing problem that an aggregator creates for a retailer when it offers flexibility from the retailer’s consumers. Nevertheless aggregation is also an opportunity for current retailers if they decided to invest in the capabilities necessary to move towards a platform type business model.

An active consumer of the future is someone who can buy and sell electricity in energy markets. In the future, industrial and home users have invested in technology that allows them to react swiftly to changing conditions. Ideally active consumers observe market price signals and react according to their needs. They increase their consumption when prices are low and decrease it when prices are high. They invest in local generation and storage systems to be able to respond to market conditions. However, today the current market design is not well adapted for a truly active consumer. As technology innovation takes root in consumers’ homes they become more flexible and have more capabilities to make their own decisions. It remains to be seen whether intermediaries will remain in the driver’s seat of consumer’s energy decisions. They may yet prove to be technology providers that enable the consumer of the future, or they may be replaced by more agile participants who are taking root in the ‘internet of things’.

3.6 Acknowledgements

This research is part of the H2020 STORY project funded by the European Commission under grant agreement number 646426-STORY-H2020-LCE-2014-2015/H2020-LCE-2014-3. The author would like to thank Prospex Institute for organizing the stakeholder meeting on business models held in Slovenia during October 2018.

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3.8 ANNEX 3.1: Business Model Archetypes Comparison

	Traditional Retailer Archetype	Innovative Retailer Archetype	Aggregator Archetype
Value proposition	Provide cheap units of power to individual households and businesses and maintain a reliable supply. (Hall & Roelich, 2016) Price hedging. (Stagnaro, 2017) BALANCING.	Energy source differentiation: green, local. (Stagnaro, 2017) Bundles with other technologies. (Stagnaro, 2017) Re-localizing energy value, in the form of a municipal services company or cooperative. (Hall & Roelich, 2016) ESCO model: efficient provision of energy services as opposed to units delivered. (Bolton & Hannon, 2016). Local renewable energy and sustainable biomass (Ecopower cbva, 2018) Bundled services: electricity, internet, TV, phone, car lease (NLE, 2018)	Energy savings due to smart management. (STORY H2020, 2018; STORY H2020 Advisory Board Workshop, 2018) Better use of available renewable energy (STORY H2020, 2018; STORY H2020 Advisory Board Workshop, 2018) Capturing economies of scale and scope in electricity markets (S. Burger et al., 2017). Services for balancing markets, offering firm capacity, operating reserves, constraint management, and secondary frequency control (S. P. Burger & Luke, 2017). Energy service provider-customer side business model (Richter, 2012b). Better routes to market for local generation. (Hall & Roelich, 2016) Fulfilling the potential of the demand side. (Hall & Roelich, 2016). Customized solutions and energy services (Richter, 2013). Consumer empowerment (STORY H2020 Advisory Board Workshop, 2018). Revenue sharing (STORY H2020 Advisory Board Workshop, 2018). Technology providers, installing better metering, smart home management systems, and communication technologies. (STORY H2020,

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			2018; STORY H2020 Advisory Board Workshop, 2018)
Value capture: revenue streams	Increase kWh sold (throughput model) (Hannon et al., 2013), (Hall & Roelich, 2016). Time of use pricing, time invariant pricing, fixed energy price (Stagnaro, 2017). Flat pricing, time of use pricing, critical peak pricing, real time pricing (ACER & CEER, 2016b; Hu et al., 2015)	Sales of energy: Time of use pricing, fixed pricing, Variable pricing. Bundled services (insurance, energy) (Stagnaro, 2017) Energy sales, biomass sales, equity sale. (Ecopower cbva, 2018)	Subscription fees, brokerage fees, commodity sales, asset sales, asset lease/rent (S. P. Burger & Luke, 2017) Sale of energy to market participants. (STORY H2020, 2018; STORY H2020 Advisory Board Workshop, 2018) Sale of grid services to grid operators (STORY H2020, 2018; STORY H2020 Advisory Board Workshop, 2018)
Customer segments	Industrial, business, and household consumers.	Industrial, business, and household consumers. Energy communities ((STORY H2020 Advisory Board Workshop, 2018).	Intermediation between commercial, industrial, municipal & Network operator. (S. P. Burger & Luke, 2017) TSOs and DSOs (STORY H2020, 2018; STORY H2020 Advisory Board Workshop, 2018)
Key Partners	Large utilities through long term power purchase agreements (Richter, 2012b). Balance responsible parties Spot exchange platforms TSOs and DSOs	Local energy providers. DSOs Balance Responsible Parties Spot exchange platforms TSOs and DSOs	Electrical & thermal storage providers (S. P. Burger & Luke, 2017) Home users Spot exchange platforms TSOs and DSOs

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3.9 ANNEX 3.2: Business Model framework applied to demonstration cases

Case 1: Residential Smart Home Management – Oud Heverlee, Belgium

The goal of demonstration case is to bring 13 houses in Oud-Heverlee off-grid by creating a microgrid at the end of the distribution line. The aim is to demonstrate the synergy of a neighbourhood strategy for flexibility and grid balancing. In order to accomplish this, everything in the neighbourhood that can store energy needs to be monitored. This ranges from the temperatures of heat storages and buildings to the state of charge of a battery. Furthermore, a centralized system needs to be able to control all the flexible devices that can shift their electricity consumption. Through the LoRa network, Actility, the aggregator involved, provides a simple solution to monitor and control all these different devices. LoRa is a long range low power network to which sensors can immediately connect and start sending data or receiving control signals.
The residential buildings are located in a single street in Oud-Heverlee, Belgium. They are located at the end of the feeder, facing the typical challenges of power quality in terms of interrupted supply and voltage profile. The zone consists of a mix of old and new houses, has 20 kW photovoltaic energy generation, hybrid PV and vacuum solar thermal energy, air to water and geothermal heat pumps as well as electric cars (STORY H2020 Project, 2018a).

<u>Customer Segments and Value proposition:</u>

Value for Residential customers (12 households):

Technology and communications installation: the customers in the demonstration project were connected to smart meters. Certain appliances, such as heat pumps, PV panels and batteries, were connected to automated controllers. A system to observe, measure and control energy use in all houses was installed.

Smart energy management: consumers are helped by the aggregator to better manage their energy consumption. Their use of energy is scheduled to minimize their energy sourcing costs.

Consumer empowerment: increase awareness about energy use of consumers.

Value for the distribution grid operator: Minimize grid exchange: Adjust the consumption to minimize the impact on the grid to improve power quality and minimize necessary network investment.

<u>Revenue Stream</u>

Monthly subscription fee paid by the consumer for the smart energy management service.

At this point in time it is not possible to monetize the value created for the distribution grid operator.

<u>Key Partners</u>

Local energy community manager: the community is managed by Think-E, an energy services and consulting company. Think-E manages the relationship with consumers, in terms of signing in to the project, information sessions, and troubleshooting.

Technology providers: Actility and ABB installed smart meters, and LoRa communication technologies. Actility receives the information and developed a controller to enable smart home management.

Distribution grid operator: Fluvius, the local grid operator, is not officially part of the STORY project, though they are aware of it. The smart meters installed are compliant with their requirements. All other installations have been done behind the meter. A the moment of the writing of this work the grid operator was not paying for the improvement in power quality that resulted from the pilot.

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Household owners: household owners agreed to participate in the project, and opened their homes to teams installing and troubleshooting technology. Their expectations are to upgrade their home technology and obtain savings on their energy bills.
Retailer: household participants already held contracts for energy supply through a retailer before the demonstration began. These contracts continue in operation throughout the demonstration. Almost all of them, except one, pay day and night tariffs. Their retailers are not part of the demonstration and consumers continue to pay their bills as they did before.

Case 2: Compressed Air Storage in Residential District- Lecale, Northern Ireland.

This demonstration illustrates the benefits and opportunities of providing electrical storage through compressed air and stored heat to areas of relatively weak existing electrical infrastructure. The location is in Lecale, a semi-rural area in the south-east of Northern Ireland. The demonstration is led by a company called B9 Energy.
The unit will help to demonstrate the ability to store and re-generate electricity with standardised technology components and will validate models for operating the unit within a residential setting both to maximise the penetration of local sources of renewable energy and to minimise transmission and distribution network reinforcement requirements. It is also intended that the unit will demonstrate applications for compressed air storage within relevant markets including system support services, capacity provision and load-on-demand services (STORY H2020 Project, 2018b). B9 Energy has developed a trading platform to optimize their trading strategies in the different markets.

Customer Segments and Value proposition:
Value Proposition for I-SEM market:
Energy trading arrangement- arbitrage: B9 Energy will bid in the I-SEM, the integrated single electricity market arrangement for Ireland and Northern Ireland. Their objective is to arbitrage between peak and off-peak prices with their CAES unit.
Capacity Remuneration Mechanism: in order to ensure that demand of electricity is always met, generators receive a payment for availability (I-SEM, 2018; SEM Committee, 2018).
Value Proposition for the distribution grid operator: the CAES unit is being installed at a distribution grid substation at 33kV/11kV. The unit can contribute to alleviating distribution grid congestion. The 11kV network hosts a tidal turbine, a wind turbine as distributed generation. Also connected to the 11kV network are 300 houses and a fish factory load. The substation itself is also connected to a large solar PV installation. B9 Energy is working closely with the grid operator, Northern Ireland Electricity Networks (NIE).
Value Proposition for distributed generation connected to feeder: due to their location almost at the end of a low voltage feeder the tidal turbine and the wind turbine are liable to curtailment due to grid constraints. They cause reverse power flows along the network at periods of low demand leading to thermal overloading constraints. The operation of the CAES unit may provide ‘load on demand’ services that would prevent the curtailment of these units.
Value Proposition for the Transmission System Operator: Eirgrid, the transmission system operator runs a programme called ‘Delivering a Secure, Sustainable Electricity System’, DS3. A new

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initiative, for volume capped competitive procurement, would allow demand side units or non-synchronous technologies such as storage to offer system services (Eirgrid Group, 2018c).

Revenue Streams

Price arbitrage in the day ahead and intraday Irish electricity market: They will generate electricity and sell it in the market when the price is high, and store energy in the form of compressed air when the price is low.

Capacity remuneration mechanism from I-SEM, a payment for availability in the integrated single energy market.

DS3 remuneration: The programme would entail a service availability obligation, with a proposed six year agreement. The remuneration for energy would be done on pay-as-bid pricing with maximum tariff rates capped to the nearest whole bid.

Key Partners

Aggregator: B9 Energy have chosen to work with an aggregator in order to manage their access to markets and balancing responsibility. Due to their small scale, and to the fact that they will need to sell energy, they will work with an aggregator. At least a 4 MW capacity is required to participate directly in the I-SEM.

Retailer: at the moment of writing this paper B9 their negotiations are not yet concluded. B9 estimates that they will purchase energy through a third party retailer and they would choose to be exposed to dynamic half-hourly prices following the I-SEM market as closely as possible.

Distribution System Operator: B9 is working closely with NIE during the installation of the CAES unit at the 33kV-11kV substation. After the installation is completed and the unit is running, B9 will need to pay grid fees for both importing and exporting energy to the network. NIE is currently transitioning from being a distribution network operator to being a distribution system operator; so there is some uncertainty regarding grid fees in the future.

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4 Annex 4: The cost benefit perspective on storage business models and regulation

Nico Keyaerts[a]
[a] Vlerick School of Business, Bolwerklaan 21, B32, 1210 Brussels, Belgium

4.1 Introduction

The necessary investments in distribution grids have been estimated at 400 billion euro until 2020, accounting for about two thirds of all estimated network investments on that time horizon (Eurelectric, 2013). This amount includes conventional investments in new capacity and replacement of aged infrastructure, on the one hand, and more innovative investments in what is commonly referred to as the smart grid.

The investment in smart grid projects tends to be more challenging than regular investment connected to the distribution system for two reasons. First, investment in the smart grid is significantly less mature. It involves for instance experimenting with novel technologies in research projects or pilot roll-outs to establish technical feasibility or financial viability before scaling up. Second, smart grid investments are dispersed leading to fragmented knowledge generation. There are indeed many small-scale demonstrations in different jurisdictions and led by different agents.

The use of cost benefit analysis (CBA) to support – not replace – the decision making process helps to address both challenges. The idea behind cost benefit analysis is to assess and compare on an equal footing the advantages and disadvantages of alternative projects considering the best available information. The CBA of a single smart grid project can then be used to assess the feasibility and viability of that project, whereas having a common CBA assessment model allows easy sharing of otherwise fragmented knowledge about which type of smart grid projects performs better in a particular system and market context.

Despite the rising importance of investment in smart grid projects (Vitiello et al., 2015), the decision processes involved are still mostly ad hoc and relying on local practices. In other words, cost benefit analysis might be used, or not. And even if it is used, the CBAs of two smart grid projects might not allow a proper comparison when their respective methods are too different in terms of the input that is considered, the way the net benefit is calculated, or the reporting of the output. A common method for cost benefit analysis could contribute to a more harmonised approach towards important smart grid projects in the many local jurisdictions and help with decisions regarding the selection of projects, the provision of regulatory incentives and the granting of financial assistance. Additionally, a common method for CBA facilitates the dissemination of knowledge and sharing of best practices regarding innovative smart grid projects.

At the EU level, following the EU energy infrastructure package (European Commission, 2013), significant progress has already been made in harmonizing the methods for cost benefit analysis of electricity (ENTSO-E, 2015), and gas (ENTSOG, 2015) infrastructure projects with European impact, the so called projects of common interest (PCI). The European Commission's Joint Research Centre (JRC) made a first effort to harmonise the assessment of smart grid and smart metering

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projects by providing guidelines for conducting a cost benefit analysis for smart grid projects. Those guidelines were a necessary and useful step at that time. Nevertheless, considering the rising importance and aforementioned challenges of smart grid investments, and the progress that has been made since 2012 on common methods for CBA of energy infrastructure projects at the transmission level, it is time to move towards a common method for CBA of smart grid projects.

In the second section of this note, we discuss ten key concerns in the three building blocks of a cost benefit analysis – which are the input, the calculations and the output – by taking stock of the respective methods for CBA of electricity transmission infrastructure by ENTSO-E (ENTSO-E, 2015), , CBA of gas infrastructure investment by ENTSOG (ENTSOG, 2015), the JRC guidelines for CBA of smart grid projects (Giordano, V, et al, 2012) .

The third section of this note highlights the key recommendations for addressing the ten concerns in a common method for cost benefit analysis of smart grid projects. A common method that should ideally be used by all research projects for assessing and benchmarking the smart grid demonstrations they develop, improving the knowledge sharing among fragmented projects and raising the understanding of the complexities of innovative smart grid investment.

4.2 Current practice in CBA of energy infrastructure projects in Europe

In this section we discuss ten key concerns for a common method for cost benefit analysis for energy infrastructure projects, each time explaining the issue and the approaches by ENTSO-E, EMTSOG and JRC. The first three concerns relate to the input side of cost benefit analysis. The next five concerns relate to the calculation of the net benefit and the final two concerns have to do with the output of the cost benefit analysis. Table 1 summarises the ten concerns and our assessment of the respective current implementations by ENTSO-E, ENTSOG and JRC.

4.2.1 Input to cost benefit analysis

On the input side of cost benefit analysis, there are three implementation issues: 1/ considering project interaction, 2/ organizing the data gathering process and 3/ provision of disaggregated cost numbers.

4.2.2 Considering project interaction

In network systems like the electricity and gas systems in Europe, the actual value of an infrastructure project has to be assessed taking into account the interaction of the project with the current and future system to find out potential positive (the economic value of the combined projects exceed the stand-alone values of the projects) or negative synergies (the value of the projects diminishes when they are combined). For smart grid projects, that are often dealing with enabling technologies, such positive synergies from interactions with other projects might in many cases be more significant than the inherent stand-alone value of those projects.

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Project interaction can be considered in the cost benefit analysis through the baseline against which the projects are assessed and through the project definition. First, to identify potential synergies, projects should be assessed against a common baseline that covers the expected development of the electricity system in a BAU scenario, and against a baseline that additionally includes other potential smart grid investments. A significant difference in the valuation of the smart grid project against both baselines signals interaction with other smart grid projects. Second, complementary projects should preferably be clustered and defined as a single project for their assessment.

The current implementations of the ENTSO-E, ENTSOG and JRC methods address project interaction to different degrees. The method for gas infrastructure investment uses a second baseline that includes other potentially investments, whereas the JRC method for smart grid projects recommends using a baseline tailored to a project.

ENTSO-E implementation
The ENTSO-E method uses a single baseline that includes the existing grid and non-PCI investment that has been included in the TYNDP. There is no assessment of the proposed project against a baseline that additionally includes other potential projects of common interest, making it difficult to discover negative synergies between potentially rivalling projects.

ENTSOG implementation
The ENTSOG method: the assessment method uses one baseline that includes the existing gas system and non-PCI investment included in the TYNDP and a second baseline that additionally includes investment and potential PCI projects

JRC implementation
The JRC smart grid method does not consider project interaction because there is no common baseline. Project promoters are encouraged to use a baseline tailored to local conditions.

4.2.3 Data gathering process

All assessments rely on forecasted data with respect to demand, supply, fuel prices, conversion factors et cetera. Considering that the conventional time horizon for the assessment of infrastructure investment is twenty years, there can be different views on the forecasted numbers. To the extent that each project uses project specific data as input into the cost benefit analysis, comparing projects becomes impossible. A common dataset with appropriate granularity and geographical scope remedies that issue.

A common dataset can build from existing forecasting exercises such as the EU's Energy Roadmap 2050 scenarios. The process to collect data should be transparent and contestable, in the sense that users of the infrastructure (consumers, generators), regulatory authorities and project promoters have to opportunity to propose and challenge numbers. Such a process provides an implicit consistency check and a minimum validation of the data.

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ENTSO-E
The data gathering process for cost benefit analysis is aligned to the data collection in the context of the ten year network development plan (TYNDP electricity) for transmission infrastructure. For TYNDP electricity, ENTSO-E predefines several scenarios with subsequent stakeholder consultation to validate the assumptions and parameters. Expectations about local developments feed into the process through their inclusion in the assumptions of the different national network development plans. The TYNDP process traditionally has focused on regulatory investment in transmission capacity, but plans to include third party projects and storage investment to be in line with the requirements of the TEN-E Regulation.

ENTSOG
The data gathering process for cost benefit analysis is aligned to the data collection in the context of the ten year network development plan (TYNDP gas) for transmission infrastructure. For TYNDP gas, ENTSOG predefines several scenarios with subsequent stakeholder consultation to validate the assumptions and parameters. The TYNDP process traditionally has focused on regulatory investment in pipeline capacity, but plans to include third party projects and storage and LNG investments to be in line with the requirements of the TEN-E Regulation.

JRC
The JRC method recommends a data gathering process that focuses on reflecting the local conditions. There is no recommendation to align the data collection for cost benefit analysis with existing data collection processes at the national level, to ensure consistency at least at the national level.

4.2.4 Disaggregated reporting of cost data

Besides the common data, the input to the cost benefit analysis include the costs of implementing the project. These costs should be reported in a disaggregated format to allow benchmarking of the cost components, with respect for confidentiality of commercially valuable information.

ENTSO-E
The method lists several cost and benefit components to be considered, but it is unclear whether the components need to be reported separately. Disaggregated reporting would allow the cost items to be benchmarked against the ACER database of unit costs for electricity infrastructure investment (ACER, 2015).

ENTSOG
The method lists several cost and benefit components to be considered, but it is unclear whether the components need to be reported separately. Disaggregated reporting would allow the cost items to be benchmarked against the ACER database of unit costs for gas infrastructure investment (ACER, 2015).

JRC
The method does not provide recommendations with regard to the disaggregated reporting of cost and benefit items.

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4.3 Calculations of cost benefit analysis

There are five implementation issues that have to be considered when calculating the net benefit of the projects that are under assessment: 1/ using a common list of significant effects, 2/ disregarding distributional concerns, 3/ providing explicit algorithms, 4/ using a common discount factor, and 5/ dealing with uncertainty.

4.3.1 Using a common list of effects

To assess projects on the same footing it is important to use a common list of effects, which are the benefits of the CBA. Rather than trying to be comprehensive for all projects, the CBA should focus on a reduced list of effects that are relevant for all projects because some benefits might only be relevant in very specific cases and some benefits might overlap.

A comprehensive list of possible effects basically includes 1/ the impact of the project within the electricity (gas) system, 2/ the externalities of the project, and 3/ the macro-economic effects.(Meeus et al, 2013) have further explored these three types of effects for electricity, their analysis is summarised below Figure 13.

The electricity (gas) system effects include the impact on the gross consumer surplus (due to changes in consumption volumes), the impact on the production costs (more efficient dispatching, balancing or ancillary services) and the impact on the infrastructure/system costs. Additionally, there could be other market effects such as increased competition or liquidity.

The externalities include the impact of the project on carbon-dioxide emissions, on the integration of renewable energy sources, on social and environmental costs and on the benefits of early deployment of new technology.
The macro-economic effects include the creation of jobs and the overall increase of economic growth.

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Figure 13: (left) Illustration of comprehensive list of effects for electricity transmission projects. (right) Illustration of reduced list of effects for electricity transmission projects. Source (Meeus et al, 2013)

A smart reduction of the aforementioned effects see Figure 13 allows a more lean cost benefit analysis that monetises in the first order those effects that are important for all projects, with the possibility of supplementary analysis in the case that a specific benefit is significant for a particular project.

Some effects can be disregarded because they are covered partially or fully by another effect; counting them separately would lead to double counting of the benefit. For instance, in Europe, the benefit of reduced carbon-dioxide emissions is internalised in the production costs through the EU ETS price. Similarly, the social and environmental costs are usually included in the project costs by complying to any restrictions in the building permit. The benefit of improved integration of renewables are typically also covered in the production cost savings by having more efficient dispatching of renewable energy sources.

The benefit of advancing the roll-out of innovative technologies, which might be significant for smart grid projects, is usually internalised in the infrastructure costs through the different EU and national policies to fund innovation.

Some effects can be disregarded because they are roughly the same for all projects. For instance, the macro-economic effects of smart grid projects is likely to be similar for all projects: they create some additional jobs during the implementation stage and are in general a driver of economic growth.

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That reduces the list of effects to consider to the electricity system effects, which are consumer surplus, infrastructure/system costs, production cost savings and other market effects.

For electricity transmission and gas transmission projects, the other market effects can be safely disregarded as they are fairly small and similar for most of those projects. For smart grid projects, on the other hand, the benefits related to (retail) market facilitation might be more heterogeneous for the different projects. In that case, their analysis should be included in the calculation of the net benefit.

ENTSO-E
ENTSO-E discusses a set of effects that need to be included in the assessment.

ENTSOG
ENTSOG discusses a set of effects that need to be included in the assessment.

JRC
The method does not propose a reduced set of significant effects, but gives a list of possible effects that could be considered. The non-exhaustive list of possible effects of smart grid project includes more than 20 effects that could be monetised, and over 50 key performance indicators that could be qualitatively assessed.

4.3.2 Disregard distributional concerns

The implementation of an electricity, gas or smart grid project is likely to affect the distribution of welfare among the economic agents. However, distributional concerns are best treated outside of the cost benefit analysis through redistributive measures such as taxes. The objective of the CBA assessment is to find out if a project is overall welfare enhancing.

The respective ENTSO-E, ENTSOG and JRC methods all disregard distributional concerns in the cost benefit analysis.

4.3.3 Explicit algorithms for calculating the net benefit

To achieve a transparent assessment of the projects, the algorithms used for calculating the net benefit should be stated explicitly so that model imperfections can be accounted for. The model should be clear on the geographical scope, the temporal granularity and to what extent technical and market constraints have been included.

Additionally, a common model could be used to make the assessment perfectly contestable by allowing interested parties to play with the assumptions while assessing potential investments. In the UK, for instance, the national CBA tool for interconnectors has been made publicly available by the regulated transmission system operator, allowing third parties to make their own assessments of their potential interconnector projects.

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Considering the effects that are to be assessed, the calculation models should be able to calculate the changes in the gross consumer surplus, the infrastructure costs and the production cost savings. This typically requires a consistent combination of grid models and market models, representative demand and supply curves, and a complete set of consistent input data. For calculating other market benefits, more advance market models are required, for instance, models that are able to capture market power.

To demonstrate the need for more advanced supplementary analysis, indicators, such as market concentration indices, could be used.

ENTSO-E
The method discusses explicit requirements for the model to calculate the net benefits.

ENTSOG
The ENTSOG method discusses explicit requirements for the model to calculate the net benefits.

JRC
The smart grid method does neither provide nor recommend to use a common model or explicitly state the used model. It does refer to definitions for the sets of key performance indicators.

4.3.4 Common discount factor

Considering that part of the benefits are captured in the future, it is necessary to correct the time-value of those benefits that are in the far future, compared to those that are captured immediately. This raises the question what discount factor to use: a high number attaches more value to immediate benefits, whereas a low number is relatively more favourable for future benefits.

Whatever the exact number, it is recommended to use the same social discount factor for the economic assessment of all projects. That approach allows discovering the best projects regardless of local risk conditions, which for most concerned projects are likely to be similar. For the financial analysis, however, it is important to use a project specific financial discount factor.

ENTSO-E
A common discount factor of 4% for all projects has been adopted

ENTSOG
A common discount factor of 4% for all projects has been adopted

JRC
No common discount factor has been proposed in the smart grid method

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4.3.5 Dealing with uncertainty

To deal with uncertainty in both the baseline and in the implementation of the project, stochastic analysis, e.g. monte carlo type analysis, or deterministic, analysis, e.g. scenarios, with respect to the main input data are necessary.

The respective ENTSO-E, ENTSOG and JRC methods, all include ways to analyse uncertainty.

4.4 Output of cost benefit analysis

On the output side of cost benefit analysis, there are two implementation issues: 1/ disaggregated reporting of benefits, 2/ making the final assessment of the projects.

4.4.1 Disaggregated reporting of benefits

Even though the total net benefit of the project is the most important decision variable, the disaggregated reporting of benefits in terms of their regional distribution and of the specific benefits of a project provide additional insights.

ENTSO-E
The method lists several cost and benefit components to be considered, but it is unclear whether the components need to be reported separately. ENTSO-E cautions that its method does not provide regional disaggregation of the effects.

ENTSOG
The method lists several cost and benefit components to be considered, but it is unclear whether the components need to be reported separately. The method foresees reporting of the regionally disaggregated net benefits.

JRC
The method does not provide recommendations with regard to the disaggregated reporting of cost and benefit items.

4.4.2 Final assessment of the projects

The final assessment on the business case of a project should be primarily based on the monetisation of the significant benefits. However, transparent adjustments might be justified to accommodate certain considerations such as double counting of effects, potential synergies with other projects, and uncertainty; all these concerns can be treated within the CBA method as elaborated throughout this chapter. When it comes to comparing different projects, it might be necessary to consider project specificity, for instance, by comparing urban grid projects distinct from projects in rural areas.

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If the final assessment includes both monetized effects and other indicators, there is not only a risk of double counting effects, but it also implies that these quantitative and qualitative indicators are implicitly monetized, leading to a less transparent and more subjective assessment.

The respective ENTSO-E, ENTSOG and JRC methods apply a form of multi-criteria analysis with explicit monetization of several effects and quantitative and qualitative indicators for other effects that are arguably difficult to monetise.

Status of implementation ENTSO-E (2015) & ENTSOG (2015) & JRC (2012)	E	G	SG
INPUT (1) Project interaction must be taken into account in the project and baseline definition	One baseline	Two baselines	No common baseline
INPUT (2) Data consistency and quality should be ensured	TYNDP	TYNDP	No common data gathering process
INPUT (3) Costs should be reported in disaggregated form	Not clear	Not clear	Not clear
CALCULATION (4) CBA should concentrate on a reduced list of effects	Reduced list	Reduced list	50 KPI + 22 EPRI effects + other qualitative
CALCULATION (5) Distributional concerns should not be addressed in the calculation of net benefits	OK	OK	OK
CALCULATION (6) The model used to monetise the production cost savings and gross consumer surplus needs to be explicitly stated	Explicit model available	Explicit model available	No common model
CALCULATION (7) A common discount factor should be used for all projects	4% for all	4% for all	No common discount rate
CALCULATION (8) A stochastic approach/scenario analysis should be used to address uncertainty	OK	OK	OK
OUTPUT (9) Benefits should be reported in disaggregated form	Not clear	Not clear	Not clear
OUTPUT (10) Ranking should be based on monetization	MCA	MCA	MCA

Table 10: 10 key concerns for implementing a common method for cost benefit analysis

4.5 10 key concerns for a common method for cost benefit analysis

Table 10 provides a summary of the aforementioned key concerns for a cost benefit analysis method. While these methods are dynamically improved based on practical experiences, it is clear that the ENTSO-E and ENTSOG methods have made more progress than the smart grid method by JRC towards a common method for cost benefit analysis.

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4.6 Lessons for cost benefit analysis of smart grid research projects

So far, smart grid projects have been evaluated using ad hoc local methods (ICCS-NTUA, AF Mercados EMI, 2015), (Vitiello et al., 2015), leading to challenges for comparing projects and for disseminating knowledge.

The experiences with the ENTSO-E, ENTSOG and JRC methods allow drawing some lessons to address those challenges, at least at the national level for demonstrations in the same country.

4.6.1 Common input

- All projects need to make assumptions on project-independent data; notwithstanding different views on forecasting these data, the assessment of the smart grid projects would benefit from a common dataset and common baseline(s).
- The project-specific data should be reported in a transparent way, allowing the numbers to be contested and to be validated.

4.6.2 Common calculation

- To facilitate the comparison of projects and the sharing of generated knowledge, a limited set of significant effects that are relevant for all projects should be used; notwithstanding the possibility of supplementary analysis for specific projects. The need for supplementary analysis could be motivated through indicators or qualitative evidence.
- The robustness of the calculations should be tested by using as much as possible the same scenarios and input ranges.

4.6.3 Common output framework

- The output of the assessment should include the total net benefit and the disaggregated benefits in a format that is easy to use and to understand.
- The primary assessment criterion should be the monetized effects.
- Additionally, adjustments in the comparison of projects could be made for project specificity such as the urban or rural character of the grid.

4.7 Acronyms and terms

CBA	cost benefit analysis
JRC	Joint Research Centre
KPI	Key performance indicator
PCI	project of common interest

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5 Annex 5: The Finnish perspective on storage business models and regulation

Ariana Ramos[a], Markku Tuovinen[b], Mia Ala-Juusela[b]
a) Vlerick School of Business, Bolwerklaan 21, B32, 1210 Brussels, Belgium
b) VTT Technical Research Centre of Finland Ltd, P.O. Box 1000, FI-02044 VTT, Finland

5.1 Introduction

This paper examines the business model and regulatory challenges of storage as a service in the Finnish market. Three main contributions are presented, first, business model archetypes are drawn from ten demonstration projects through interview and literature research; second, the Finnish regulatory framework for storage as a service is analyzed; third, implementation enablers and challenges faced by project developers are outlined.

In order to identify the main business model and regulatory challenges the following methods are used: first, a review of the main academic literature was carried out to identify the key components of the storage as a service business model; and second, interviews were conducted with relevant stakeholders of ten innovative storage projects in Finland. Two main business model archetypes are identified through the case studies. Storage is used for either 'behind the meter' solutions or to provide services to either the DSO or the TSO. Most of the projects studied, at the time of this writing, are still in a demonstration phase. Based on the literature, and case studies, the main enablers and challenges of the battery as a service business model are presented. The main enablers are the scalability of the business model and digitalization of the business process. While the main challenges are data accessibility, satisfying the demands of a multi-customer environment, and smart management of aggregated systems.

Finland is the first country in the world to have adopted smart electricity metering (hourly metering and remote reading) on a full scale. The consumption and production of electrical energy in 3.4 million electricity metering points are measured today on an hourly level, and the validated metering data is available the next day for use by the customer, balance settlement and the electricity markets. The legislation on this first-generation smart metering came into force in 2009, and the transition period to hourly-level metering ended on 1 January 2014. DSO's in Finland are now starting rollouts of next-generation electricity meters, which are capable of receiving, implementing and forwarding load control commands with higher reliability and better response times. Today the controls being delivered still vary in response times depending on the reading technology. The next-generation reading technology and systems will be planned in such a way that they are modifiable also into entities implementing a higher-frequency reading and control cycles easily and at reasonable cost. This is important enabler for demand response and utilization of battery energy storage systems even at end customer's homes.

Historically, electricity had to be consumed at the moment that it is generated. Power systems are carefully managed to maintain this balance between supply and demand. Now, however, storage technologies such as batteries, heat storage, and fuel cells are mature enough to be commercialized and made available to the public. These technologies allow network users to use energy at a later time than when it was generated. In this way storage can be thought of as a load when it is absorbing

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energy and as generation when it is discharging energy. Storage is a key element for enabling the energy transition from fossil fuels to renewable energy. Renewable generation is variable and subject to natural resource availability, therefore the ability to store it enables its large scale integration into power systems. The added value that small and medium sized storages can bring in the distribution grid is studied in a H2020 project called STORY. In the initial large scale simulations made in the STORY project the benefits of big amount of small and medium sized storages in a network with high level of RES integration can be clearly seen: With storage operation, self-sufficiency and self-consumption levels were increased, network losses were decreased and RES impact on the network was mitigated. From a commercial point of view, the large scale roll out of storage is still in it's infancy. The institutional environment that allows economic activity for storage owners is not yet mature. The definition of storage across different countries is yet to be harmonized, access to markets is still a barrier especially for smaller projects, smart technology platforms are still being tested, and business models for storage are not always profitable.

In order to study the business models of storage as a service this paper is structured as follows. Section 5.2 presents an definition and overview of BESS as a service. Section 5.3 presents an overview of 10 case studies of storage in Finland. Section 5.4 presents the Finnish regulatory framework. Section 5.5 outlines business model and regulatory recommendations. Finally section 6 presents the main conclusions of the study.

5.2 Battery energy storage systems as a service

Storage as a service is defined through the different applications that storage can have across the electricity value chain. The Clean Energy Package for all Europeans defines energy storage as 'deferring the final use of electricity to a moment later than when it was generated, or the conversion of electrical energy into a form of energy which can be stored, the storing of such energy, and the subsequent reconversion of such energy into electrical energy or use as another energy carrier (European Parliament and the Council of the EU, 2019). This section explores how storage

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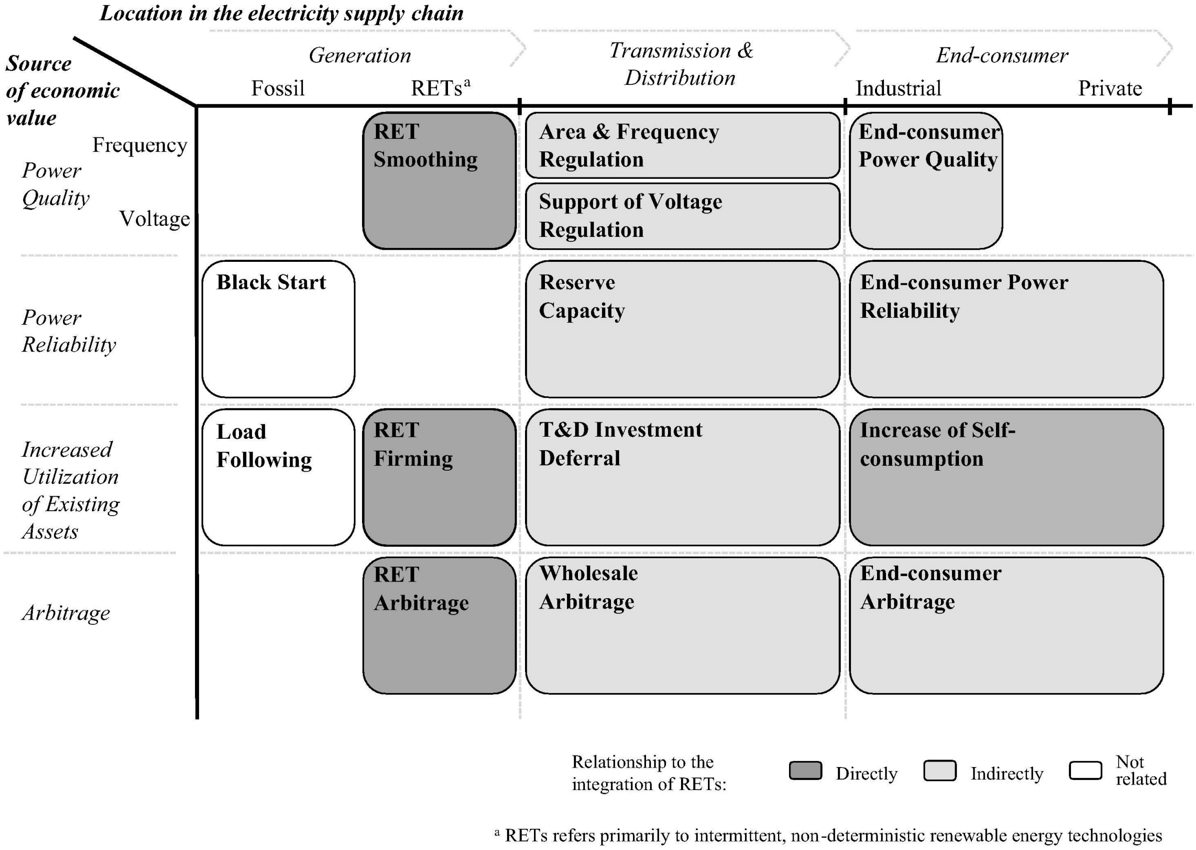

Figure 14: Classification of energy storage applications reproduced from (Battke & Schmidt, 2015)

assets can be exploited to provide services. First, literature is presented regarding the applications of storage in different settings. Second, the place of storage within the distributed energy resources ecosystem is explored. Third, a definition of business model framework is presented as the basis for the analysis of the case studies of storage in Finland. Finally, based on the literature presented, the main methods used to analyse the case studies in the following sections are presented.

Academic literature has defined several applications for storage energy systems. The authors in (Davis & Hiralal, 2016) find that batteries can be used to maximize returns locally by storing energy when it is cheap and using it when it is expensive, or be aggregated to match supply and demand. Using a net present value methodology, the business case for a household is found not to be profitable and incentives are proposed. A mapping of energy storage service business models in the Netherlands finds possible business applications for end-consumers, for TSOs and DSOs, and for energy companies. (Mir Mohammadi Kooshknow & Davis, 2018). The authors find that electrical and thermal storage offer services mainly in the reserves markets, and non-electricity services; while their revenue streams come from asset sale and leases, as well as commodity sales. A mapping of storage technology applications is first presented in (Battke & Schmidt, 2015), as can be observed in Figure 14, a classification is based on the value propositions that storage can offer for different market parties: generators, transmission and distribution operators, and industrial and private end consumers.

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	Demonstration Site	Year	Capacity [MW]	Capacity [MWh]	Location in EVC	Business model	Notes.
1	Suvilahti (Helen, Helsinki)	2016	1,0	0.6	PGC/AGG	Delivery of the Technology	Delivery for a PGC in the solar farm of Kalasatama distr providing services for TSO and local DSO (Helen).
2	Fortum (Järvenpää)	2017	2,0	1,0	PGC	Delivery of the Technology	Delivery is part of local power plant in Järvenpää. It is u and tear on the hydropower plant.
3	Logistics Center Hakkila (Vantaa)	2017	NA	NA	PRO	Service	Comprehensive service concept for solar farm and micr Helen. Readiness for providing services for TSO and loc
4	Atria (Nurmo)	2017-19	1,0	1,0	PRO	Service	Comprehensive service concept for solar farm and micr Nurmon Aurinko Oy for Atria Oy.
5	Cello Shopping Centre (Espoo)	2018	2,0	2,1	PRO	Service	Comprehensive service concept for solar farm and micr Vibeco Oy (Siemens) Oy for Sello shopping centre. Provi
6	Logistics Center (Lidl, Järvenpää))	2019	2,6	NA	PRO	Delivery of the Technology	Comprehensive delivery for solar farm and micro grid pr Electric for LIDL. Provides services for TSO.
7	LEMENE (Marjamäki, Lempäälä)	2019	2,4	1,6	PGC/PRO	Delivery of the Technology	Comprehensive delivery for solar farm and micro grid w portfolio.
8	Fortum (Kuru, Ylöjärvi)	2019	NA	NA	AGG	Service	Service for Elenia (DSO) and TSO provided by Fortum.
9	Tuuliwatti (Simo)	2020	6,0	NA	PGC	Delivery of the Technology	Delivery for wind farm or Tuuliwatti Oy. Investment dec
10	Caruna (Inkoo)	2020	NA	1,0	AGG	Service	Service for Caruna (DSO) and TSO provided by Fortum.
			17,0	5,7			
				NOTES.	EVC = Energy Value Chain. PGC = Power Generation Company. AGG = AGGregator and/or service provider. PRO = PROsumer.		

Table 11: Battery energy storage system demonstrations in Finland.

The place of storage within the distributed energy resources ecosystem is explored. The authors in (Taylor, Bolton, Stone, & Upham, 2013) present a taxonomy of services that can be offered by storage depending on the module size and its discharge time at rated power. The study finds that storage can offer services from seconds, minutes or hours as reserve and response services, transmission and distribution grid support and bulk power management. They place the services that storage can offer inside a complex ecosystem where the institutional environment encourages or discourages the deployment of storage while making a difference between user-led storage, decentralised systems embedded on the grids, and centralised systems. Business model archetypes for distributed energy resources have been explored based on publicly available information of 144 companies (S. P. Burger & Luke, 2017). Another attempt at categorizing the environment in which storage can offer services is the ‘smart grids reference architecture’ proposed by (CEN, CENELEC, ETSI, & Smart grid coordination group, 2012). This methodology proposes five layer covering different inter-operability aspects required for the coordination of complex smart grids services. The business layer represents the business information exchange related to products and services of market parties involved. The functional layer describes the functions and services including the relationships of their different components. The information layer describes the information that is being used between functions, services and components. The communication layer describes protocols and mechanisms for the interoperable exchange of information. The component layer is the physical distribution of all the participating components in the smart grid.

A business model describes how a company plans to create value for its customers and capture a portion of the value it creates (Chesbrough & Rosenbloom, 2002; Osterwalder et al., 2010; Zott et al., 2011). Nine basic building blocks of a business model are identified: customer segments, value propositions, channels, customer relationships, revenue streams, key resources, key activities, key partnerships (Osterwalder et al., 2010). For simplicity, in the analysis that follows, two of these

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building blocks are used: value proposition, and customer segments. Due to the characteristics of energy markets storage projects have different possibilities to access markets, therefore project size, or aggregation of storage assets is contrasted to the value that storage creates for the different customer segments.

In summary, storage projects can be classified according to their value proposition and the customer segments comprised in each proposition following the categorization presented by (Battke & Schmidt, 2015). Equally important, is the placement of storage within the energy value chain. Value propositions differ in terms of the type of service that storage can provide. Two main categories can be identified:

- Storage as a solution for behind the meter optimization.
- Storage as a service to system operators and market parties.

This simplified framework is used as a methodology in the subsequent analysis of storage projects in Finland. While the value proposition and stakeholders have been clearly identified in the literature, there is a gap concerning the challenges faced by storage project developers. This paper, adds a contribution to the literature by analysing the placement of storage within an ecosystem of distributed energy solutions, and the challenge of providing services in a multi-customer environment.

5.3 Practical review of battery energy storage system demonstrations in Finland

Finland is today one of the most advanced smart grid markets in the world providing an ideal test bed for smart grid applications - including also battery energy storage systems and services. Today there are approximately 10 battery installations in Finland (see Table 11), which are providing services for different stakeholders in the energy value chain. First, the case studies are classified based on the framework presented above, and second the main concerns raised in the interviews conducted are outlined.

5.3.1 Case study classification

The STORY-project implemented short interviews of the project organizations and some other key stakeholder's to clarify how they see the coming regulatory and market frameworks and what kind of activities are needed to contribute the utilization of the battery energy storages in Finland. The STORY-project was also interested in clarifying the comprehensive interpretation of operators in energy value chain how they see battery energy storages and their potential (see Figure 14). First, the different stakeholders that benefit from the battery storage system applications are described. Second, the owners of the storage systems, and their place in the electricity value chain is identified. Third, the implications of the ownership and value propositions are discussed.

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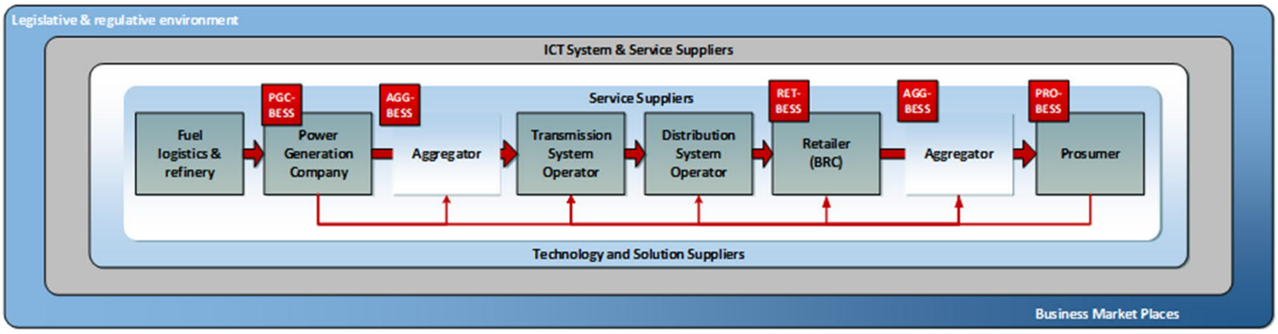

Table 1: The battery energy system options in the energy value chain.

First, a summary of the case studies conducted is presented in Table 11 and the main stakeholders benefitting from the storage applications are described. Out of the ten case studies presented, five are used for local asset optimization and five provide services to other parties. For example, the demonstration site in Jarvenpaa is used to reduce wear and tear on a hydropower plant. The unit at Tuuliwatti, is located at a wind power park, and will provide load on demand when the electricity price is too low or the grid is congested. Services to the TSO, in terms of balancing power are offered by six of the projects. Congestion relief for the DSO is offered by four of the projects, all of these also offer services to the TSO. See Box 1 for a description of a demonstration providing services to a DSO at the Kuru site.

Second, ownership of the storage systems and their place in the value chain is explained. Today battery energy storage systems can be owned and operated by the Power Generation Company (PGC), the Retailer (acting typically also as Balance Responsible Company (BRC)), the Aggregator and the Prosumer. Out of the cases studied, five are located at generation facilities, while one of those is managed by an aggregator and one is considered a prosumer as it is also linked to a microgrid. See Box 1 for a description of the microgrid solution at Lemene. Five are located behind

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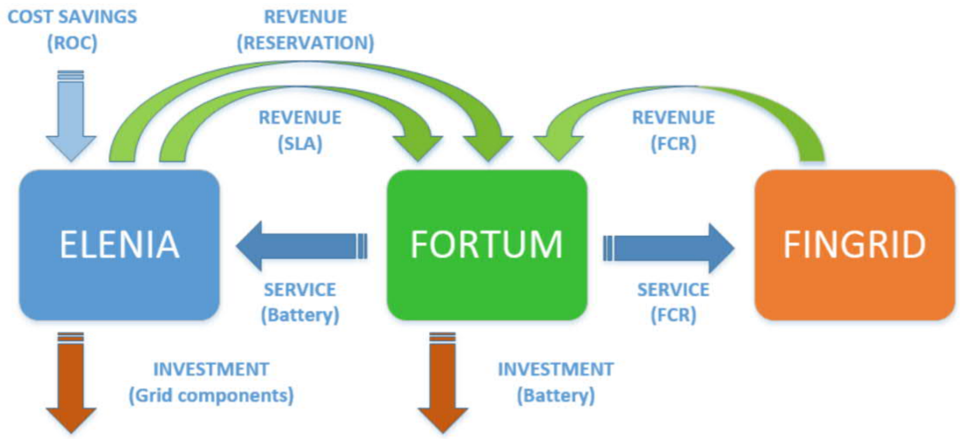
the

BOX 1: Battery Energy Storage System as a Service (Kuru)
Fortum, an energy service company, and Elenia a DSO, have developed and implemented completely new operating model in the energy sector. The companies are together testing the suitability of electricity storage in maintaining electricity system balance and in reducing power outages. Combining various ways of using electricity storage offers Fortum an opportunity to develop an electricity market solution that benefits customers and electricity markets alike. In this model, Battery Energy Storage System is utilised the TSO's reserve markets as part of the Fortum Spring virtual battery and reduction of the power outages in Elenia's distribution network.

Fortum owns and operates the Battery Energy Storage System. It was installed in Elenia's grid area in Kuru, in North Pirkanmaa, during 2019. The Battery Energy Storage System is connected to Elenia's medium-voltage network, and the batteries will supply electricity to a limited grid area during a power outage. This makes it possible to keep the electricity running in a limited area during repairs. The battery pack can secure the supply of electricity for over one hundred customers for several hours. In normal situations the battery pack will function in the reserve markets as part of the Fortum Spring virtual battery along with thousands of household hot water heaters. The capacity of the virtual battery is offered to TSO's (Fingrid) reserve markets as regulating power.



meter at prosumer premises. Three projects are managed by aggregators. At the moment the value of the battery energy storages systems for the Retailer's business processes is moderate and there is no applications or pilots in that field. The Aggregator may work in B2B or B2C business or both. In Finland there are still challenges in the independent aggregator model - it should include information exchange between parties, handling of imbalances and the requirements for developing data systems. The independent aggregator model is not yet possible in Finland.
Third, the implications of the business model and value propositions are discussed. The differentiation of the various BESS solutions is not straightforward - from the customer point of

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view it may be a delivery of the technology or delivery as a service (Bess as a Service). The service options may differ from each other. The customer may not need any investments and is paying service fees only in the case when the technology is delivered as a service. In another model, the customer can do the investment and pay service fees for operation and maintenance, for example. The customer may utilize all solution options for providing services for third parties, which may be DSO or TSO. Services for third parties may be provided by the customer or alternatively by the service provider operating the solution for the customer, which may not have competence or interest to do that.

5.3.2 Main concerns raised in interviews

As discussed earlier the energy storage specification, regulation and legislation are all under discussion in Finland at the time of this writing but different stakeholders are already demonstrating and testing solutions and services actively. The Smart Grid Forum, established by the Ministry of Economy and Employment (MEAE), continues now the regulative and legislative work taking also into account the practical experiences in different demonstrations. Based on the interviews, the main observations and conclusions from the demonstrations are:

1. The coming regulation and legislation will be based on the principle that the ownership of energy storage is not a part of DSO's or TSO's business but they may both buy energy storage services from third parties. According to stakeholder's experiences this principle works well, when there is service providers available to meet the local flexibility need. Today the business environment is still evolving and very few service providers are available. Today the TSO's reserve market has major importance as a revenue flow. The question remains as to whether it ensure business interests of service providers in all local sites. Due to the low amount of service providers, DSO would like to be allowed to own and operate battery energy storage systems - but under surveillance of Energy Market Authority (EMA) only and after EMA's acceptance process.
2. The price level of the battery energy storage systems is still too high and one revenue flow is not sufficient for a solution to be competitive. Stacked revenue models are needed but they in turn make the battery energy management solution more complicated. This is one clear R&D need. Only few stacked revenue and business models are now developed and more practical data is needed to analyse their actual competiveness. Generally spoken the service provider's dilemma is to find a local need and utilize battery in the reserve markets (mainly FCR-N in Finland). In 2020 the FCR-N price is 13.2 €/MW,h and the estimated volume is 87.1 MW.
3. Higher flexibility of the power generation and higher system flexibility provided by a battery energy storage systems and demand response are all core elements in the future energy systems. Hydropower is today a proven form of flexible power generation and it is therefore the main resource in the flexibility markets in Finland. From the present power system point of view hydropower flexibility is developing too slowly and it is also vulnerable to strong mechanical stresses in fast control actions. The battery energy storages can be integrated to hydro power plants as well to extend the lifetime the plant as to optimize the revenues in the reserve markets (e.g. FCR (Frequency Containment Reserve), FFR (Fast Frequency

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Box 2: Battery Energy Storage System in the energy community (Marjamäki, Lempäälä)

The LEMENE smart energy system is under construction in Marjamäki business area near the city of Tampere in Finland. The project will deliver the largest energy self-sufficient business district using renewable energy in Finland - the planned scheduled completion is in 2019. LEMENE project has been granted an investment aid by the Ministry of Economic Affairs and Employment.

Energy system in Marjamäki consists of 4 MW of solar power (2MW + 2 MW plants), gas engine capacity of 8,1 MW, fuel cell solutions providing a total of 130 kW, and a battery to even out temporary fluctuations in energy production. An important part of the project is to secure energy availability as renewable energy production varies. The energy self-sufficient grid operates mainly as part of the public electrical grid but it can also operate as a supporting reserve system for the public electrical grid, or as an independent off-grid, on demand. All this is enabled by automation solutions adapted to the micro-grid.

The Battery Energy Storage Systen (1.6 MW) is delivered by Merus Power representing state-of-the-art power electronics and control system technology. It mainly comprises of Lithium-ion batteries and battery management system, power conversions system (PCS) and main Merus MCC controller. A special feature of the Batter Energy Storage System is the power quality improvement functionality, which can be utilized continuously regardless of energy storing or discharging

Box 1: Microgrid solution in energy community

Reserve, established in Q2/20120.)). Fortum's Batcave - project is a good example of this kind of application.

4. The future smart grid components include renewable and other energy sources, storages and loads, which are more or less controllable. Various changes will occur with respect to the power quality such as voltage values and harmonics as well in conventional transmission and distribution grids as well in future micro grids. Harmonic filters provide a solution for real-time cancellation of harmonic distortions created by non-linear loads to ensure compliance with power quality standards and recommendations. Active harmonic filters are a versatile solution to deliver power factor improvement, voltage variation control, flicker mitigation and load balancing functionality. Most of the battery energy storage systems in Finland are today equipped with harmonic filters.
5. Micro grid environments are now very interesting topic in Finland. They are connected to the local grid i.e. they are not real self-sufficient micro grids. Micro grid environments include commercial buildings (Case Sello shopping centre), industrial districts (case Lemene and Atria) or alternatively Energy communities. According to the EU commission, the energy communities are one core element in the future energy business environment. In Finland they are, like in whole EU, in a learning phase concerning regulation, legislation, and the business itself. Micro grid environments are always local solutions to meet local needs. Depending on the strategy and competence of a customer, they may select solution or service

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option. It is also important to identify business opportunities outside the micro grid environment by providing services for different customer segments (e.g. local DSO, TSO).

6. Most of the BESS's will be part of larger entity such as Virtual Power Plant (VPP) or Virtual Battery (VB) service concepts, which both may be based on aggregation of different resources. The concepts may have different goals and customers but the main aspect is that both services require a digital energy management service platform, which is integrated to the Battery Management System (BMS) and possibly also to other flexibility resources. The key R&D question is today, how to develop applications and business models for multi-customer environments and how to manage different operational uncertainties.

Finland is a small country having very high technical expertise and strong collaborative working culture. Smart Grid group (2017 - 2019) and Smart Grid Forum (2020 ...) are collecting all relevant parties together and they discuss and try to achieve common understanding how to implement EU Commission's goals to local regulation, legislation and even to the business - concerning also battery energy storage systems. This has given guidelines for starting fast battery energy storage systems demonstrations. In addition to that, Finland has strong culture focusing on core business functions and there is always plenty of space for services. It is, however, noticeable that battery energy storage systems or services are demonstrated only by larger companies, which have got typically 30% investment support. According to Ministry of Economy and Employment (MEAE) will not be any more support available for battery energy storage system demonstrations unless they are part of bigger entity. It must be noted here, that every country has own challenges and/or problems related to power system flexibility i.e. how to balance demand, production, import/export and flexibility elements such as BESS. It is related especially to local TSO's responsibility in balance management and frequency regulation. TSO's service providers must always meet the country or area specific service level requirements with their solutions.

5.4 Finnish Regulatory Framework

The legislative landscape on Battery Energy Storage is evolving also in Finland - naturally according to European legislative landscape but simultaneously analysing new proposals and directives and their interpretation when designing and implementing them to Finnish legislation. There are two interest groups, which have proposed modifications to the legislation; 1. The Smart Grid Working Group (Ministry of Economic Affairs and Employment in Finland) and 2. Finnish Energy (ET), which is a branch organisation for the industrial and labour market policy of the energy sector. ET represents companies that produce, procure, distribute and sell electricity, gas, district heat and district cooling and related services. This section outlines the regulatory framework for storage in Finland. First, the definition of storage in Finnish regulation is presented. Second, the ownership of storage in regulation is discussed, as it was identified above that it is a key aspect in the current demonstration projects. Third, the participation of flexible consumers in electricity markets is examined.

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First the definition of storage is presented. In the energy tax law the electricity storage is defined as an entity for storage short term electricity electrochemically. The entity of the electricity storage consist of devices, systems and buildings. Electricity storage may be electrochemical storage such as lead, lithium-ion or flow battery or a condenser. Pumped storage power plants and power to gas plants are from taxation point of view consumers, not electricity storages. The owner of the stationary electricity storage should apply a license for operating a tax free storage, if the electricity is distributed to consumption. The license application is made to Finnish tax administration. If the electricity is not distributed to consumption, the license cannot be given. The electricity storages in the transmission and distribution grids are part of the corresponding grid. The electricity storages in power plants are considered as part of the power plants and charging and discharging is announced with the own production of the plant. The Finnish energy tax law was updated in 8.11.2019 to cover also electricity storage. The Finnish energy tax law is thus only legislative/regulative document, where the electricity storage is now considered. The regulative and legislative work is now under preparation - Smart Grid Forum is responsible for the work.

Second, provisions regarding storage ownership are discussed. The present Finnish Electricity Market Act does not include specific provisions concerning ownership, development, management and operation of energy storage and they are thus not defined in the current electricity market regulation. According to the Electricity Market Act DSOs/TSOs may not own, manage or operate generation facilities and TSOs' and legally unbundled DSOs' right to purchase electricity is limited only for certain purposes (for covering network losses). Finnish Energy Authority has stated that, the ownership of energy storage is not a part of DSO/TSO business but they may buy energy storage services from third parties. According to the Smart Grid Working Group owning and operating of electricity storage facilities may not be done by a local monopoly i.e. DSO. A DSO may, however purchase services from a market party and commercial operators. According to Finnish Energy's (ET) the DSO must primarily procure the storage from the markets but it is in certain specific circumstances in the customers' advantage that DSOs are also allowed to procure and own storage. This may be the case if the DSO wishes to enhance the power quality or replace traditional network investments with storage and there is no storage capacity available from the markets for a certain location. From the DSO's point of view, the location of the storage is crucial. If the DSO is going to enhance the power quality of some specific grid branch, the storage must be located exactly in that grid branch. Finnish Energy takes the view that the DSO's should be allowed to procure and own storage whenever it is technically and economically rational. Market analyses should not be required for these.

Finnish Energy (ET) takes also the view that storages owned by the DSOs would be part of their regulated network assets. The regulator should ensure that the storages owned by the DSOs would only be used for the statutory DSO operations, such as development of security of supply and power quality. The Finnish National Regulatory Authority (NRA) should also ensure that the DSO does not sell any storage capacity for applications that are the responsibility of market parties. Storages owned by the DSOs (as non-risk investments) must not cause any market distortion for other actors operating in the competitive markets. Information acquired by Finnish Energy indicates that the DSOs would not oversize their storages, so that there would be no free storage capacity. In general, there is no specific risk of overinvestment in storages that would diverge from other DSO investments. Storages would be just one of the new solutions the DSOs could use to ensure security

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of supply and power quality as cost-effectively as possible. Furthermore, storages would be noted in the DSO's network development plan, allowing the regulator to prohibit certain storage investments, if necessary.

Electricity storage facilities may also be owned and operated by an independent flexibility service provider, which is an actor that is not customer's electricity supplier or balancing service provider and that does not need a contract with customer's supplier or balancing service provider while acting on the market. In Finland the existing legislation does not provide sufficient support for community ownership. Local Energy Communities (LEC) are not yet specified and thus not entitled to own, establish, or lease community networks and to autonomously manage them. Therefore design of national regulation on energy distribution systems arises as a key factor realizing LEC development. A translation of these provisions into national legislation will be left to the member states and implementation to National Regulation Authorities (NRA).

Third, the participation of consumers in electricity markets is examined. In Finland, the Smart Grid Working Group is of the opinion that customers should have the opportunity to participate in demand flexibility themselves or with the help of a market actor. The working group proposes that demand flexibility services, the storage of electricity and the provision of new services to customers should be considered as competitive business activity as competition will ensure customer-driven and needs based development of products and services as well as efficiency [Pahkala et al.].

5.5 Business model recommendations

Business model recommendations are abstracted from the case studies, literature review and regulatory framework for storage in finland. The recommendations are presented first in terms of enablers, and second in terms of challenges for the service business model.

5.5.1 The key enablers for the service business model

The BESS as a service model is a challenging business model – different expertise and solutions are needed, increasing also the costs of the service deliveries. The service business model, however, enables the utilization of different revenue flows when serving different customers in different business sectors - and even in numerous geographical locations. Scalability of the business model is thus the core element of the service business model.

If a company is targeting to provide services instead of technology solutions, it should identify customer specific service process portfolio, develop and operate processes utilizing digital solutions and monitor process KPI's to meet customer needs and requirements as documented in a Service Level Agreement (SLA). Digitalization of the service processes is the key enabler for the service business model - especially for it's scalability. The BESS solutions have been piloted already quite widely but the service model is still under development and only few practical test cases can be identified. The key enablers identified for the development and implementation of the service business model are:

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- Clarity and stability of the operational business environment. The new EU electricity market directive gives the guidelines but there are still open questions having impact on business calculations, taxation as an example.
- Technical feasibility analysis. Every local solution must be studied, designed and customized for the local market place before integration to the distribution grid. The BESS may be integrated also to DSO's ICT-infrastructure allowing it's operation directly from DSO's supervisory control and data acquisition system (Scada). New system functions in Scada system and related system integrations are needed.
- Economic feasibility analysis. Before the investment decision can be made, the investor should study and analyze the main and potential revenue flows for economic evaluation of the site's payback potential. Valuation of the BESS services is still quite challenging and case specific requiring also plenty of data (e.g. load profiles) and their analysis.
- Characterization of systems dynamics and interoperability. Smart Grids with different resources and controllable elements such as BESS and Demand Response (DER) are dynamic and usually also quite fragile systems. To ensure the overall system operability, dynamic characterization of the resources should be carried out as a risk management task.
- Digital service platform. In addition to the Battery Management System (BMS) and control solution also a General Energy Management Service (GEMS) platform is needed. The GEMS's role is to optimize the operation of the BESS for each customer and also take the responsibility from overall optimization concerning the charging and discharging i.e. optimization of SoC (State of the Charge). The GEMS should be responsible also for other key functions such as forecasting, resource aggregation and data transfer, KPI-monitoring and reporting.
- Subcontractor network and system integrations. The service business model is typically an integrated service portfolio delivered and controlled by the main contractor and main service provider - the BESS as service provider. The service provider has several subcontractors delivering their own systems and/or services. Importance of the service processes is to integrate all subcontractors systems and services to one entity serving the customer according to SLA.
- Redundant data communication networks. The BESS as a service provider is providing services from central location, where also the GEMS system infrastructure locates. The BESS's are distributed in the future widely in different geographical locations. This requires fast, reliable and redundant data communication networks.

5.5.2 Key challenges for the service business model

As noted earlier the BESS as a service model is a challenging business model. Plenty of different expertise and solutions are needed and they are not necessarily at commercial level as a service option due to lack of digital solution or platform. The key enablers mentioned in previous chapter may be in some extend also key challenges. Here some further aspects are listed, which have been identified during the research work.

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- Service providers access to relevant demand and distribution grid data. BESS as a service provider should study both the technical and the economic feasibility of the system to be able to make investment decision. In Finland the DSO has the metering and data delivery responsibility for other energy market participants, but this may not be the case for all European countries.
- Control and management of the BESS under uncertainties. In minimizing total cost of the BESS, the General Energy Management System (GEMS) platform need to consider several uncertain factors such as generation, load and electricity market price profiles, peak power and tariffs. Since the charging and discharging scheduling of BESS is typically done day-ahead, under the presence of forecasting error, day-ahead scheduling can be problematic, specifically for managing peak load [Minsoo Kim et al.]. Every installation is individual and has own portfolio of uncertainties to be modelled, managed and controlled.
- Utilization of portfolio of revenue flows i.e. operation in multi-customer environment. One of the most promising applications of the BESS is the participation in frequency regulation FCR (Frequency Containment Reserves). The BESS can perform either FCR-N (in Normal operation) or FCR-D (in Disturbances), or both. The BESS can achieve full power is few hundreds of milliseconds compared to traditional reserve power suppliers tens of seconds. The energy capacity stored in the batteries is limited, however, and exhausted in continuous activation. The frequency regulation is thus just one service option for the BESS asset owner, which's goal is to a) discover additional revenue flows for profitable operation of a BESS and b) develop enabling solutions and/or services for benefitting them all or part of them.
- Management of the service level requirements in a multi-customer environment. In order to make a profitable business case, a BESS as a service should have several customer segments, which all have their own service level requirements and KPI's, which are typically documented in the Service Level Agreement (SLA). In most cases the services are quite business critical i.e. if the service do not meet the SLA requirements, the business target's can not be achieved. It is quite challenging to optimize charging and discharging of the BESS and simultaneously service all customers properly according to SLA.
- Value based service pricing and/or value sharing in a multi-customer environment. When the services are provided to the present market places such as FCR-N or FCR-D, the valuation of the revenue flows can be estimated based on volumes and prices with sufficient accuracy. The BESS is, however, capable of providing a suite of thirteen general services to the electricity system [Rosewater D. et al.]. The BESS can be sited at three different levels: 1. behind the meter, 2. at the distribution level, or 3. at the transmission level. The BESS's deployed at all levels on the electricity system can add value to the grid. The key questions are 1. how much they add value and 2. how accurate the value estimation is. Is it high and accurate enough to encourage market-driven 3rd party investments in BESS units. These services and the value they create generally flow to one of three stakeholder groups: customers, utilities, or Transmission System Operator (TSO).

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- Optimal charging enabling agreed service provision i.e. discharging. State of Charge (SoC) is one critical parameter of a BESS when valuating it's actual service capability. The forecasting models are used to determine feasible charge and discharge schedules that supply grid services [Rosewater et al.]. Smart grid controllers then use SoC forecasts to optimize BESS schedules to make grid operation more efficient and resilient. Forecasting the local renewable production, electricity demand and price of the electricity in different market places are core elements in efficient utilization of the BESS.
- Emphasis on operational costs. Battery energy storage systems as a service contracts start with periods as short as a few months. Contracts are based on a regular monthly or annual fee. Terms can be adapted to fit changing business needs. Customers receive guaranteed 24/7 system reliability for zero asset investment and with low implementation costs, including comprehensive service coverage. All implementation, operation and maintenance costs, performance guarantees and warranties are typically covered under one contract and fee. The service provider has also strong interest to R&D&I work and new customer specific services are launched from time to time - there is no need to own competence development or employment. DSO is always interested in making investments due to the Finnish regulation model. Service model increases DSO's operative costs, which is not desired tendency.

5.6 Conclusions

This paper analysed the business model of battery energy systems as a service in the Finnish context. The study was carried out first, through a literature review of BESS as a service, and second through a case study of ten demonstration projects across Finland. The case studies were conducted as part of the STORY H2020 project, which aims to integrate energy storage into distribution systems. Interviews were carried out with project participants and regulatory authorities in order to create a full picture.

The literature study shows that the value proposition of storage, as well as the main stakeholders involved, are clearly defined. There is a gap, however, in outlining the challenges that project developers are facing while implementing storage as a service business models. Storage technology must be seen as part of an ecosystem. The challenge of integrating components into a demonstration is evidenced by the findings of this paper.

The regulatory framework in Finland is open to innovation, technology is progressing faster than regulation, and stakeholder discussions are taking place. At the same time, smart meters have been implemented for years already, and DSOs are capable of monitoring smart meter data on an hourly level. The main issues identified in regulation are the right to own storage given to commercial rather than regulated parties and access to markets by final consumers or communities.

Two main business model archetypes are identified through the case studies: the use of storage for 'behind the meter' technical solutions, or the use of storage to provide services to either the DSO,

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TSO or other market parties. The storage as a service business model is complex, as it may separate asset location, from ownership and value creation. The main enabler of the storage as a service business model is concluded to be scalability of the business; while the main challenges are data accessibility, possible conflicting demands of a multi-customer environment and smart management of aggregated systems under uncertainty.

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This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 646426

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6 Annex 6: The distribution tariff impact on storage business models and regulation

Tim Schittekatte[a,b,c] and Leonardo Meeus[a,c]

[a]Florence School of Regulation, Robert Schuman Centre for Advanced Studies, European University Institute, Via Boccaccio 121, I-50133 Florence, Italy
[b]Réseaux Innovation Territoire et Mondialisation Université Paris-Sud, 91400 Orsay, France
[c]Vlerick Business School, Vlerick Energy Centre, Bolwerklaan 21, B-1210 Brussels, Belgium

Abstract[24]
Battery adoption by residential consumers, mostly coupled with a new or existing solar PV system, is expected to rise in the near future. In that regards, distribution network tariff design plays an important role. The network tariff design should align the business case of storage with the impact it has on the local grid. We evaluate capacity-based network charges and two types of network charges which stimulate self-consumption: net-purchase and bi-directional volumetric network charges. We show that when grid costs are sunk, all network tariff design options will over-incentivise battery adoption at the expense of the overall cost of the system. In contrast, when many future grid costs are to be made, the considered network tariff design options will mostly under-incentivise battery adoption, and potential system-level gains are missed out. Besides the network tariff design, also time-varying energy prices do improve the business case of storage. The impact of interactions between the network tariff design and time-varying energy prices on the total system costs need more investigation.

Keywords: Batteries, distributed energy adoption, distribution network tariff design, game-theory, non-cooperative behaviour

6.1 Introduction

Electrical energy storage, mainly in the form of lithium-ion batteries, is becoming a factor in the residential solar market. Schill et al. (2017) state that in Germany in 2015, nearly every second small-scale PV system was installed together with a battery. By the end of 2016, summing up to about 48,000 'prosumage' systems were installed. Maloney (2018) notes that 20% of Sunrun's customers have chosen to install solar plus storage systems in California in early 2018, in parts of Southern California that total is as high as 50% of sales. Greentech Media estimates that battery installations will reach a rate of more than 1300 MW per year by 2022 in the US (GTM Research and Energy Storage Association, 2017). The business case of batteries is mainly a function of two forces. On the one hand, the strongly decreasing investment costs (see e.g. RMI (2015)). On the other hand, the reduction in the electricity bill that can be achieved by battery adoption. In this paper, we focus on the latter. In that regard, rate design, more specifically distribution network tariff design plays an important role. Distribution network charges represent on average around 30 % (incl. VAT) of the final electricity bill in Europe, with a maximum of around 50 % in Norway and a minimum of around 15 % in Italy (ACER & CEER, 2018c).

[24] This paper benefited from the financial support of Project STORY – H2020-LCE-2014-3 - European Union's Horizon 2020 research and innovation programme under grant agreement No 646426.

Historically, volumetric distribution network charges (€/kWh) were in place in most jurisdictions around the world. This practice is being challenged in recent years. More specifically, volumetric charges with net-metering, implying that a consumer's network charges are proportional to its net consumption from the grid over a period of time (e.g. month), are deemed inadequate with the massive deployment of solar PV. Consumers with solar PV pay significantly lower network charges but still rely on the distribution grid as much as they did before. In other words, such network charges serve as an implicit subsidy for solar PV which ends up being paid by consumers without solar PV.[25] Therefore, regulators in many countries are thinking to suspend net-metering and move more towards network tariffs which are capacity-based (€/kW) or stimulate self-consumption of the on-site generated electricity (CEER, 2017; European Commission, 2015; Hledik, 2014). Such types of distribution network charges are deemed to align better what consumers pay for the network with the costs they cause. Batteries are identified as a key enabling technology to allow the reduction of capacity needs of a consumer or to allow for more self-consumption.

The impact of distribution network tariff design on the business case for residential electricity storage is the topic of this paper. More precisely, it is analysed whether the network tariff design aligns the business case for residential electricity storage with wider system benefits. We show that depending on the assumed grid cost structure, i.e. whether most grid investments are sunk or many grid investments still have to be made, batteries can be over-or under-incentivised by the design of the distribution network tariff; the network tariff can act as an implicit subsidy or a tax for storage adoption.

Besides the network tariff design, an additional important driver for the business case of residential storage is time-varying energy prices. With time-varying energy prices, a battery can also be used for energy price arbitrage aside from solely reducing grid fees. Ceteris paribus, with time-varying energy prices instead of flat energy prices, the business case for storage will improve. However, a consumer, when deciding about the adoption and operation of storage, will look at the possible reduction in her final electricity bill instead of at each separate cost component (network charges, energy costs and taxes and levies) in isolation. Therefore, there is an interaction between network tariff design and energy price arbitrage.

The following of the paper is structured as follows. In Section 6.2, the evaluated distribution network tariff designs are introduced. In Section 6.3 , the methodology is described. Two models are used. A game-theoretical model with which the alignment of incentives of individual consumers and the wider system is evaluated and a central planner model that serves as a benchmark. The full model formulation is not treated in the body of the text but can be found in Appendix A. In Section6.4 , the setup and data for the numerical example are described. In the core of the paper, Section 6.5 , results are shown and discussed. The result section is split up into four parts. First, we show the results for the case that all grid costs are assumed sunk. Second, we show the results for the case that the grid costs are driven by the aggregated consumer peak demand. Third, we look at how time-varying energy prices impact the results. Fourth, we show that there exists a theoretically

[25] See e.g. the blog post by Lucas Davis (March 2018): https://energyathaas.wordpress.com/2018/03/26/why-am-i-paying-65-year-for-your-solar-panels/

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optimal network tariff design, so-called critical peak pricing, which approximates the outcome of the central planner under given assumptions. Lastly, in Section 6.65 a conclusion is presented, and policy implications are derived.

6.2 Evaluated distribution network tariff designs

In this section, the three evaluated network tariff designs are introduced. First, we describe capacity-based network charges. After, two types of network charges which stimulate self-consumption are introduced: net-purchase and bi-directional volumetric network charges.

6.2.1 Capacity-based network charges

With capacity-based network charges, also called (maximum) demand charges in the US, a consumer pays for the grid according to his (individual) monthly or yearly peak capacity usage averaged per e.g. an hour. Simshauser (2016) finds that capacity-based charges resolve issues with volumetric network charges such as rate instability and wealth transfers between solar PV and non-solar PV adopters. The idea behind capacity-based charges is that as the main driver of the network is (peak) network capacity, it makes sense to charge consumers according to their maximum network capacity needs. The problem is however that individual consumer maximum capacity-usage does not always coincide with the main network cost driver, the aggregated peak capacity need over a group of consumers connected to the same network.

In that regard, Simshauser (2016) notes that if the capacity-based charge overstates the value of peak load, it may pull-forward battery storage to an extent that it is not cost-efficient anymore. Similarly, Brown and Sappington (2018) find that capacity-based charges tend to be relatively effective at enhancing welfare when the demand for electricity is relatively sensitive to price and when the peak demands of all consumers occur during the same period. However, welfare gains are a lot more modest when the peak demands of many residential customers do not coincide with the system-wide peak demand for electricity. Finally, Passey et al. (2017) present a method to assess the cost-reflectivity of capacity-based charges visually and test different implementations. They use Australian data and find that standard capacity-based charges to have low cost-reflectivity in terms of aligning customer bills with their contribution to the overall network peak demand. The authors continue by arguing that the potentially significant adverse impacts on the economic efficiency of such tariffs is an issue that does not appear to have received sufficient policy attention. However, more advanced implementations significantly improve the cost-reflectivity. An example are capacity-based charges that are only levied during the months in which the aggregated peak demand occurs.

6.2.2 Self-consumption incentivising network charges

Besides capacity-based network charges, we also evaluate two distribution network tariff designs that stimulate self-consumption.[26] With net-purchase volumetric charges, a consumer pays a

[26] Self-consumption is defined as the direct use of PV electricity on the same site where it is produced, with a smaller amount of electricity fed into the grid.

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€/kWh fee for all electricity withdrawn from the network. Contrarily to the historical practice of volumetric charges with net-metering, the meter does not turn backwards when excess electricity is injected in the network. With bi-directional volumetric network charges, a €/kWh network fee is paid for each kWh of electricity withdrawn and injected into the network.[27]

By creating a difference between the value of on-site generated electricity that is self-consumed or injected back into the network, this network tariff design incentivise self-consumption. On one extreme, volumetric network charges with net-metering did not stimulate self-consumption at all, i.e. the grid acts as a free battery, and the price a consumer receives to inject 1 kWh into the grid is always equal (or even greater) than the price a consumer pays to consume 1 kWh from the grid. On the other extreme, volumetric network charges with bi-directional metering, i.e. a consumer has to pay a volumetric network charge to withdraw and a volumetric network charge to inject electricity in the grid, will give the incentive to minimise the exchange of electricity with the grid and thus to maximise self-consumption. The incentive to self-consume under volumetric charges with net-purchase lies in the middle.

Different self-consumption policies have been implemented in different countries. Luthander et al. (2015) describes that for example Italy had a self-consumption premium and that also China has recently introduced a similar self-consumption subsidy. The authors add that also in Germany there was a bonus for self-consumed electricity between 2000 and 2012. However, since 2012 the price a consumer received to inject one kWh of electricity into the grid fell below the final price to consume one kWh of electricity (energy cost, network charges plus taxes and levies). As such, self-consumption has become profitable even without the extra incentive and the bonus has therefore disappeared. Similarly, Green and Staffell (2017) explain that an electricity tariff is in place in the UK which triples the value of stored energy due to the arbitrage value of avoiding exports and storing electricity until it is consumed.

6.3 Methodology

Two models are used to do the analysis: a game-theoretical model and a central planner model. First, we describe the game-theoretical model. After, the central planner model is briefly described. The game-theoretical model is used to capture the interaction between the distribution network tariff design, decentralised decision making of self-interest pursuing active consumers investing in solar PV and batteries, and their aggregated effect on the network costs. The model was first introduced in Schittekatte and Meeus (2018). In Schittekatte and Meeus (2018) the model was used to analyse the trade-off between cost-reflective and fair distribution network tariff design. The central planner model serves as a first-best benchmark. The full formulation of both models can be found in the Appendix A.

6.3.1 Game-theoretical model

The game-theoretical model has a bi-level structure. A regulator is represented in the upper-level. The regulator decides upon the distribution network tariff in place anticipating the reactions of the

[27] We assume in this analysis that the fee to withdrawn has the same magnitude as the fee to inject.

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consumers represented in the lower-level. The objective of the regulator is to minimise the total system cost under the condition that the total network costs equal the network charges collected from the consumers. The total system costs consist of four components: total grid costs, total retailer energy costs, total DER investment costs and other costs.[28] The relative share of the different components of the total system costs are a function of the incentives of the consumers, i.e. the mix of the energy sourced from the retailer and delivered by the grid and the energy delivered directly from installed DER at the consumer-side.

The total grid costs can consist of two parts: sunk grid costs and prospective grid costs. Sunk grid costs are the costs of grid investments made in the past to be able to cope with electricity demand in the future and these costs are unaffected by the utilisation of the network. Prospective grid costs are variable (in the long-run) and a function of the maximum coincident network utilisation of all consumers. The higher the coincident peak, the higher the network costs to be recovered. Abdelmotteleb et al. (2017), Pérez-Arriaga et al. (2017) and Simshauser (2016) describe that the coincident peak demand (or exceptionally the injection if higher) is generally considered as the main cost driver of a distribution network. Next to the coincident peak demand, other network cost drivers can be identified, such as thermal losses and the investment cost to replace electronic components (e.g. protection) to deal with bi-directional flows due to high concentrations in PV adoption (see e.g. MIT Energy Initiative (2015) and Cohen et al. (2016)). These other network cost drivers are not included in the current analysis.

Consumers react to the electricity bill as a whole, but the accounting of the cost components is separate as we consider an unbundled setting. Besides the endogenously considered network charges, the consumers buy electricity, the commodity, from a retailer who bought this energy in the wholesale market and sells it to downstream consumers for an exogenous price. Finally, next to the retailer energy price and the network charges, a consumer pays taxes and levies; the level of these costs is considered invariant, and the way these are collected does not interfere with the analysis. Modelled consumers can be passive or active. Passive consumers are assumed not to react to prices; active consumers pursue their own self-interest, i.e. their objective is to minimise the cost to satisfy their electricity demand. They have the option to invest in two technologies, solar PV and batteries, to lower their dependence on grid supplied electricity.

The incentives of the active consumers will not always align with system benefits and can have negative distributional consequences. An intuitive example is what happens with volumetric charges with net-metering in place. In that case, an active consumer will be incentivised to install solar PV; the investment cost of solar PV is compared to the avoided retailer energy costs and network charges. From a system perspective, the total retailer energy costs will go down as consumers buy less energy from the retailer, the total DER investment costs will go up due to investment in solar PV and the total grid costs will more or less stay the same as stand-alone solar PV does not affect the grid costs much. High PV generation and the aggregated consumer peak demand often do not coincide. As a result, the reduction in grid charges for consumers is higher than the avoided grid cost. Overall, the total system costs might even go up due to the solar PV

[28] Other costs represent taxes and levies recovered from consumers; it is assumed that the total level of these costs is invariant.

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adoption compared to a situation in which no consumer installs solar PV.[29] In addition, the network charges (in €/kWh) need to increase to allow full grid cost recovery. As a result of this increase, mostly passive consumers, which did not install solar PV, will see their electricity bill increase. Similarly, in this paper, we focus on battery adoption and do this analysis for capacity-based charges, net-purchase volumetric charges, bi-directional volumetric charges in Sections 6.5.1 to 6.5.3 and for (time-varying) peak-coincident network charges in Section 6.5.4. .

Mathematically speaking the model is formulated as a Mathematical Program with Equilibrium Constraints (MPEC). An equilibrium is obtained if all grid costs are recovered and none of the consumers has an incentive to adapt their electricity withdrawal and injection pattern from the grid by e.g. installing more solar panels or using installed batteries in an alternate fashion. Different methods exist to solve the model. In this case, the model is reformulated as a Mixed Integer Linear Programme (MILP) which can be solved using commercial off-the-shelf optimisation software. For a complete treatment of different solution methods see Gabriel et al. (2012).

6.3.2 Central planner model

Besides the game-theoretical model, a centralised planner model is used as a benchmark. The difference with the game-theoretical model is that there is no distribution network tariff formulated in the central planner model; the consumers do not need to be coordinated. Instead of consumers acting in their own interest, the central planner decides unilaterally about their actions.[30] The central planner model is formulated as a linear programme (LP). By comparing the results for the evaluated network tariff designs with the game-theoretical model and this benchmark, we can show how much storage is under- or over incentivised due to imperfect distribution network tariff design. Also, the impact on system cost due to the imperfect network tariff design can be estimated.

6.4 Numerical example

In this section, the numerical example is described. The section is split up into four subsections which each consider a different group of input data. This data is used to calibrate the model. It should be noted that the demand and solar PV profiles presented in subsection 6.4.1, the baseline consumer bill presented in subsection6.4.2 and the grid costs as described in subsection 6.4.3 are the same as used in Schittekatte and Meeus (2018). Results for additional consumer profiles can be found in Appendix B.

6.4.1 Consumer types, demand and solar yield

Two consumer types are modelled for simplicity: passive and active consumers, as is also done in Brown and Sappington (2017a, 2017b, 2018) and Schittekatte et al. (2018). The passive consumer does not have the option to invest in solar PV and batteries, unlike an active consumer, who can opt

[29] Disregarding the environmental benefits of the adoption of solar PV.

[30] Please note that no economies of scale in terms of battery investment are considered, e.g. a battery of 250 kWh energy capacity is cheaper than 25 batteries of 10 kWh. If that would be the case, an additional advantage of the central planner approach would be to invest in a couple of large batteries instead of a multitude of smaller batteries per household as also discussed in Schill et al. (2017).

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to invest in DER. Passive consumers do not have the financial means, are strongly risk averse or are uninformed about the possibility to invest in DER. Active consumers minimise their costs to meet their electricity demand and may invest in DER to do so. At one extreme, all consumers can be passive, as in the recent past. At the other extreme, all consumers can be active, i.e. install DER when it can reduce their overall electricity cost. Reality presumably lies in the middle. Some consumers will remain passive for a number of reasons. Other consumers could be installing DER even when they do not financially profit from it, but because of other reasons which are harder to monetise, e.g. independence from the grid, sustainability motives etc. In the numerical example, it is assumed that 50% of all consumers are active and 50% are passive.[31] The consumer demand and solar PV yield profiles are represented using a time series of 48-hours with hourly time steps and are shown in Figure 15 (left). The yield per kWp of solar PV installed is shown in Figure 15 (right).

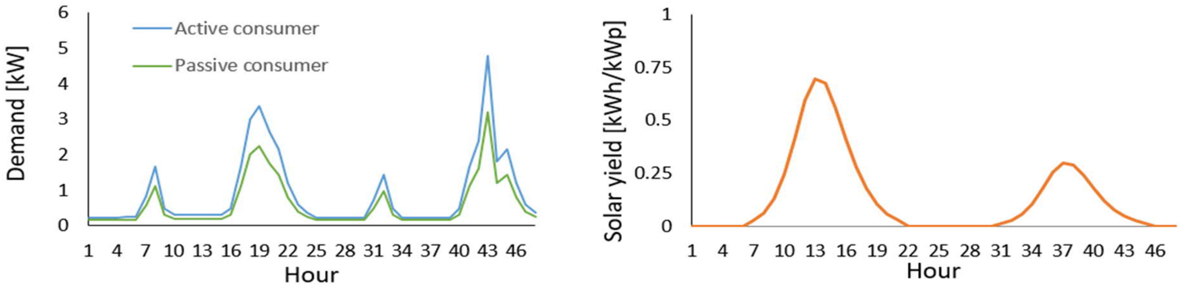

Figure 15: Original 48-hour electricity demand profiles (left) and PV yield profile (right)

The household demand for electricity shows for both modelled days a small peak in the morning and a stronger peak in the evening, the typical 'humped-camel shape' (Faruqui & Graf, 2018). For both consumer types the shape of the demand profile is identical; however, it is scaled differently. As a result, passive consumers have a slightly lower electricity demand than active consumers. The passive consumer has an annual consumption of 5,200 kWh with a peak demand of 3.2 kW and the active consumer a 7,800 kWh annual consumption with a peak demand of 4.8 kW. In Europe, average annual electricity consumption per household ranged from 20,000 kWh (Sweden) to 1,400 kWh (Romania) in 2015. In the same year, the average electricity consumption per household in the USA was about 10,800 kWh (EIA, 2016). The idea behind this difference in the levels of consumption is that active consumers are expected to be more affluent than passive consumers and that affluent consumers have higher electricity needs. This statement is a simplification of reality, but evidence for it is found in the literature (e.g. Borenstein (2017) and Hledik et al. (2016)).

The yield per kWp of solar PV installed, as shown in Figure 15 (right), scales up to 1,160 kWh per year. As a reference, this level is similar to the average yield in the territory of France (Šúri, Huld, Dunlop, & Ossenbrink, 2007). Seasonality is introduced in the PV yield profile by having a daily average PV yield of 40% of either side of the annual mean. The peak demand coincides with the day with the low PV yield. Letting the peak demand day coincide with the day with lower solar

[31] 50 % active consumer might seem quite a lot today. Today many consumers are passive because they are indifferent or vulnerable. A lower proportion of active consumers result in a lower impact of distortive network tariff design on total system costs. However, distortions result in costs shifts from active to passive consumers. In their turn, these cost shifts could again convert more (indifferent) passive consumers into active ones, increasing the impact of the distortion. Also, with dropping costs in DER, rising electricity bills, digitalisation and more climate awareness, a proportion of indifferent passive consumers might turn active.

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irradiation and vice-versa produces two effects. First, a high capacity of PV installed does not necessarily mean that the peak demand can be reduced. Faruqui and Graf (2018) investigate load profiles in Kansas and find that after the installation of PV systems, logically the net energy consumption reduces; nevertheless, the peak demand is virtually left unchanged. Second, if a high capacity of PV is installed, the injection peak of active consumers can become significant.

6.4.2 Baseline consumer bills

In Table 12 the baseline consumer electricity bill, paid by the consumers when no consumer installs any DER technology, is shown. However, if active consumers decide to invest in DER, the relative proportion and absolute values of the bill components can change for both the active and the passive consumers. The annual electricity cost for the active and passive consumer equals respectively 1,340 €/year (0.172 €/kWh delivered) and 971 €/year (0.187 €/kWh delivered). This total cost is near the average electricity cost for EU households in 2015, which was estimated at around 0.21€/kWh (Eurostat, 2016). In the USA, the average electricity cost in 2015 was around 0.125€/kWh (EIA, 2016). The consumer bill is based on information from the Market Monitoring report by ACER and CEER (2016). There, the breakdown of the different components of the electricity bill for an average consumer in the EU for the year 2015 is presented. The energy component in the EU in 2015 is estimated at 37%. In absolute terms, this is a cost of 0.077 €/kWh. Further, 26% of the bill consisted of network charges, and 13% are RES and other charges. Finally, an important chunk of the bill (25%) consists of taxes. A value-added tax (VAT), averaging 15%, must be paid and additional (ecological) taxes, averaging 10%, are raised in some countries. In this work, the VAT is integrated into the three components of the bill. Please note that a typical consumer bill varies from one country to another (e.g. ACER and CEER (2016) for the EU).

Table 12: Consumer bill in the baseline scenario (no investment in DER by active consumers)

Bill component	Recovery	Cost per year Active	Passive
Energy costs	0.08 €/kWh	624 €/year (46 %)	416 €/year (43 %)
Network charges	Default: 0.062 €/kWh In the analysis: least-cost network tariffs	485 €/year (36 %)	324 €/year (33 %)
Other charges	Fixed fee (no interference with the analysis)	231 €/year (17-24 %)	
Total electricity cost		1340 €/year (0.172 €/kWh)	971 €/year (0.187 €/kWh)

In the result sections 6.5.1 and 6.5.2, the retailer energy price is set at a constant rate of 0.08 €/kWh in order to isolate the impact of distribution network tariff design. In Section 6.5.3, two time-of-use (TOU) energy pricing schemes are introduced. To be able to compare results among the three energy price profiles, the TOU energy price schemes are scaled to make sure that in the baseline scenario (no DER) the weighted average energy price per consumer type is equal over the different energy price profiles. This means that the average TOU energy price will be slightly lower than 0.08 €/kWh. This is because consumers have a higher demand during the times that the energy prices are relatively higher for these profiles. Other charges are recovered through a fixed fee and as such do not interfere with the analysis. However, this is not always the case. How to collect such charges, or whether they belong in the electricity bill at all, is beyond the scope of this work, see e.g. the paper of Bohringer et al. (2017) in which the German case is discussed. The network charges are in

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the baseline case recovered through (net-metered) volumetric charges equal to 0.062 €/kWh. In the results presented in Section 6.5, different network tariff designs are evaluated.

6.4.3 Grid cost structure

The values for the parameters of the grid cost function (Eq. A.9) are derived from the 'baseline network costs' of the modelled consumers (shown in Table 12) and are a function of the proportion of active and passive consumers. With 50 % active and 50 % passive consumers, the (scaled) coincident consumer peak demand equals 4 kW in the baseline scenario, and the average grid costs equal 404 €/consumer.[32]

In Section 6.5.1 grid costs are assumed 100% sunk. In Section 6.5.2-6.5.4, all grid costs are assumed to be driven by consumers. In that case, the incremental grid cost is set to 101 €/kW. As a reference, Brown et al. (2015) assume the (annualised) cost to be 75$/kW.

6.4.4 DER investment cost and technical parameters

Two DER technologies are assumed at the disposition of active consumers: solar PV and batteries. A scenario with low PV but also battery investment costs can be expected to materialise soon as pointed out by many studies (Lazard, 2016b, 2016a; MIT Energy Initiative (2016a); RMI, 2015).

The investment cost of solar PV is set equal to 1250 €/kWp. Under flat energy prices, this means that the levelised cost of energy (LCOE) of solar PV is 0.086 €/kWh.[33] Excluding grid charges, an active consumer is assumed to receive 98 % of the retailer energy price when injecting solar energy.[34] An important assumption is that no investment subsidy for PV is introduced in this work and no reduced social losses from environmental externalities due to the installation of solar PV are accounted for. Table 13 shows the other DER parameters. Technical DER data is in line with Schittekatte et al. (2016).

Table 13: Financial and technical DER data

Parameters PV related	Value	Parameters battery related	Value
Lifetime PV	20 years	Lifetime battery	10 years
Discount factor PV	5 %	Discount factor battery	5 %
Maximum solar capacity installed	5 kWp	Maximum battery capacity installed	No limit
Price received for electricity injected (% of retailer energy price)	98 %	Efficiency charging & discharging	90 %
		Leakage rate	2 %

[32] 4kW = 0.5*4.8 kW + 0.5*3.2 kW and 404 € = 0.5*485 € + 0.5*324 €

[33] In the model applied, the LCOE of solar PV is a function of the investment cost of the PV panel, lifetime, discount factor, the PV system performance ratio and importantly the solar PV yield profile, which is location dependendent.

[34] This percentage is deliberatly not set equal to 100 % but just below. The reason is that if it would be 100 %, excluding the impact of the network tariff design, an active consumer would be indifferent in self-consuming or injecting the solar PV energy. This could lead to modelling issues. Setting the selling price equal to 98 % instead of 100 % of buying price has no significant effect on the results.

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Sensitivity is done regarding the batteries investment costs. Investment costs between 350 €/kWh and 100 €/kWh with steps of 50 €/kWh are tested for. All batteries are assumed to have a C-rate of 1, i.e. the battery can fully (dis)charge in one hour. Schmidt et al. (2017) find that regardless of electricity storage technology, capital costs are on a trajectory towards US$ 340± 60kWh^{-1} for installed stationary systems and US$175±25$kWh^{-1}$ for battery packs by 2027-2040. Hledik et al. (2018) reviewed many studies and are more bullish. They state that the investment cost of residential storage could be declined to 250 $/kWh by 2025.

As mentioned before, what matters for the business case of residential electricity storage is how the battery investment costs measure up against the reduction in the electricity bill that can be made by investing in batteries. The point of this work is not to obtain an estimate about at what exact investment costs residential storage becomes financially viable. Instead, the aim is to analyse the interactions between the business case for storage and the distribution network tariff design. As an alternative to ranging over different values for battery investment costs, the results could be tested for different magnitudes of the grid costs recuperated through the electricity bill.

6.5 Results

In this section, we show and discuss the results obtained with the numerical example. We show the results for the three considered network tariff structures: capacity-based charges, net-purchase volumetric network charges and bi-directional volumetric network charges. More specifically, per network tariff design we show the capacity of storage adopted by the active consumers compared to the benchmark. Also, we compare the total system costs, a proxy for overall cost-efficiency of the network tariff design.

The section is split up into four parts. First, we show the results for the case that all grid costs are assumed sunk. Second, we show the results for the case that the grid costs are driven by the aggregated consumer peak demand. Third, we look at how time-varying energy prices impact the results. Fourth, we show that there exists a theoretically optimal network tariff design, so-called critical peak pricing, which approximates the outcome of the central planner under the given assumptions.

6.5.1 Sunk grid costs

First, grid costs are assumed to be 100% sunk, a short-term vision, i.e. the grid is over-dimensioned, and the electricity usage of consumers has no effect on the total grid costs. In some countries, also policy costs are recovered through the network charges, which from a cost allocation point of view is no different than recovering sunk network costs. In Table 14, the capacity of the battery installed per active consumer is shown for the different distribution network tariff designs. Sensitivity analysis regarding the investment costs of the batteries is done. The benchmark is the central planner. Also fixed network charges (€/consumer) give the same results as the central planner. This is true as it is assumed that all grid costs are sunk, no consumers go off-grid completely and that all externalities (e.g. CO2 emissions) are priced correctly in the other components of the electricity bill.

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The results are split up in three parts to single out the interaction between investment in solar PV and batteries by active consumers. First, it is assumed that there is no possibility for the active consumer to invest in solar PV. Second, the active consumer is free to install solar PV up to 5 kWp if this investment lowers its costs to fulfil its electricity needs. Third, it is assumed that the active consumer always installs a 5 kWp solar PV installation at its premises.[35]

Table 14: Battery and solar PV investment per active consumer for the different network tariff designs under different investment cost assumptions for batteries and interaction with solar PV investments. All grid costs are assumed sunk.

Distribution network tariff design		Benchmark – central planner/ fixed charges [€]	Capacity-based [€/kW]	Volumetric Net-purchase [€/kWh]	Volumetric Bi-directional [€/kWh]
Investment cost batteries		Battery installed per active consumer [kWh] / PV in brackets [kWp]			
No PV installed, only batteries can be invested in by the active consumers	350 €/kWh	0 (0)	3.7 (0)	0 (0)	0 (0)
	300 €/kWh	0 (0)	3.7 (0)	0 (0)	0 (0)
	250 €/kWh	0 (0)	3.7 (0)	0 (0)	0 (0)
	200 €/kWh	0 (0)	3.7 (0)	0 (0)	0 (0)
	150 €/kWh	0 (0)	4.7 (0)	0 (0)	0 (0)
	100 €/kWh	0 (0)	6.8 (0)	0 (0)	0 (0)
Batteries and PV can be installed in by the active consumers	350 €/kWh	0 (0)	3.4 (3.2)	0 (5)	0 (0.7)
	300 €/kWh	0 (0)	3.6 (1.4)	0 (5)	0 (0.7)
	250 €/kWh	0 (0)	3.6 (0.5)	0 (5)	0 (0.7)
	200 €/kWh	0 (0)	3.7 (0.4)	0 (5)	0 (0.7)
	150 €/kWh	0 (0)	6.9 (3.7)	0 (5)	0.6 (0.7)
	100 €/kWh	0 (0)	9.6 (4.8)	4.9 (5)	2.2 (1.4)
Active consumer has a 5 kWp solar PV, batteries can be invested in	350 €/kWh	0 (5)	3.2 (5)	0 (5)	0 (5)
	300 €/kWh	0 (5)	3.2 (5)	0 (5)	0 (5)
	250 €/kWh	0 (5)	3.2 (5)	0 (5)	4.9 (5)
	200 €/kWh	0 (5)	6.4 (5)	0 (5)	4.9 (5)
	150 €/kWh	0 (5)	6.5 (5)	0 (5)	13.3 (5)
	100 €/kWh	0 (5)	9.7 (5)	4.9 (5)	13.3 (5)

Figure 16 shows the impact on the total system costs of the different distribution network tariff designs. Again the results are split up for the three cases of solar PV investment and the results are shown relative to the benchmark.

[35] In modelling terms, this means that first for the active consumers the maximum capacity of solar PV installed is set equal to 0 kWp. Then, the maximum capacity of solar PV is set to 5kWp and the minimum capacity of solar PV is set to 0 kWp. Lastly, both the maximum and the minimum capacity of solar PV are set to 5kWp. For the passive consumers, the minimum and maximum capacity of solar PV (and batteries) are always set to zero.

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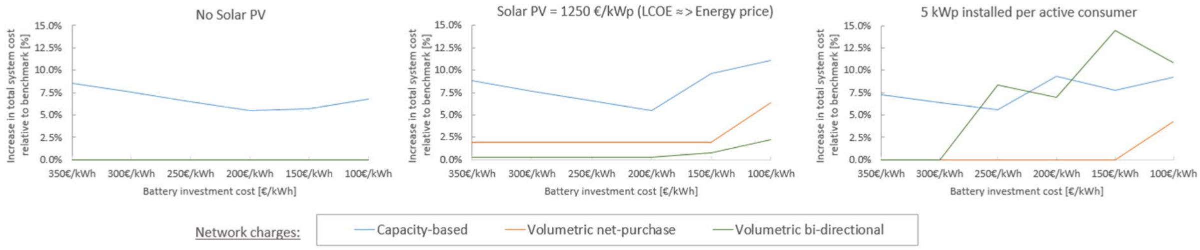

Figure 16: Increase in total system costs for the three network tariff structures when compared with the benchmark. Sensitivity for three different assumptions regarding solar PV adoption and the investment cost of storage.

Three observations can be made from Table 14 and Figure 16. First, capacity-based network charges over-incentivise battery adoption for all runs. Under capacity-based charges, active consumers can lower their individual peak demand by investing in a battery. By lowering their peak demand, they reduce their individual grid charges to be paid. But as we assume that grid costs are sunk, the total grid costs do not reduce. Therefore, when looking at the overall system cost in Figure 16, an increase results, due to the investment in batteries by active consumers and accompanied energy losses in the battery. The reductions in grid charges by the active consumers are simply transferred to the passive consumers who see their electricity bill increase, and the investment cost in batteries by active consumers adds to the total system costs. The blue line in the left graph in Figure 16, which represents the cost of the distortion under the given assumptions, has a U-shape. This can be explained by the fact that the cost of the distortion is a function of the capacity of batteries adopted, the losses in the batteries and the investment costs of batteries. Logically, the cheaper batteries are, the higher the capacity of the batteries installed and the higher the losses are but, the lower the cost per kWh of battery installed. The results for when active consumers can invest in both batteries and solar PV in Table 14 show that there are some synergies between solar PV and battery investment under capacity-based network charges; higher capacities of solar PV are installed than under the benchmark network tariff, and the capacity of the batteries generally increases when compared to the case when no solar PV investment is enabled.

The second observation is that no investment in batteries is made under the network tariff designs which incentivise self-consumption when no solar PV investment is enabled or when batteries are relatively expensive. It makes sense that under these network tariff designs, no batteries are invested in when no solar PV is enabled. In that case, the only other potential revenue from a battery investment would be arbitraging the energy price, but the energy price is assumed constant. This assumption is relaxed in Section 6.5.3. The left graph in Figure 16 shows that these two tariff structures have the same performance as the benchmark, i.e. they do not cause any distortions. The middle graph in Figure 16 shows that under net-purchase volumetric charges there is a constant minor distortion, excluding the case when the battery investment costs are 100 €/kWh. This can be explained by the fact that the active consumers each invest in 5 kWp while under the benchmark in no solar PV is invested; net-purchase volumetric charges over-incentivise solar PV adoption in this case.[36] The cost of the distortion is rather small as the LCOE of solar PV is just slightly higher than

[36] 1/ This over-incentive is much less strong than under volumetric network charges with net-metering and a function of the coincidence of the solar PV generation and the demand of the consumer. 2/ This distortion vanishes in the right graph in Figure 16 as in that case also 5 kWp is assumed to be installed by the active consumers under the benchmark network tariff, thus there is no difference in solar PV investment anymore between the benchmark and net-purchase volumetric charges.

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the energy price. A similar but less significant result is found for volumetric charges with bi-directional metering as less solar PV investment is done by the active consumers.

Third, when active consumers have solar PV installed, and batteries are relatively cheap, batteries with a significant capacity are invested in under the network tariff designs that strongly incentivises self-consumption. In that case, it makes sense for an active consumer to invest in a (relatively cheap) battery to avoid paying network charges by increasing self-consumption. We split this observation up into two. First, when the active consumer can choose to invest in solar PV, it can be seen in Table 14 that under net-purchase volumetric charges, the over-investment in solar PV can suddenly also trigger a significant over-investment in batteries. This happens when the battery investment costs drop to a low level. Again, this battery investment does not lower the grid costs and slightly increases the retailer energy costs due to losses. Therefore, the orange line in the middle graph in Figure 16 shows a strong increase at that point. Second, when assumed that 5 kWp solar PV is already installed per active consumer, batteries are most over-incentivised under bi-directional volumetric charges. As a result, the self-consumption rate increases from 32.4 % without batteries to 59.0 % with batteries of 250 €/kWh to finally 80.8 % when the cost of batteries reaches 150 €/kWh.[37] This means that if the cost of batteries drops to that low level (alternatively, if the grid charges are very high), it is optimal for an active consumer to install a battery in order to strongly reduce the injection of any electricity generated by its solar PV panels into the network. Figure 16 (right) shows that this distortion has a high cost at relative cheap battery prices. The cost of the distortions becomes even higher than under capacity-based charges.

6.5.2 Grid costs as a function of the aggregated consumer peak demand

In this subsection, the other extreme in terms of grid cost scenario is examined. Instead of assuming the grid costs to be sunk, they are assumed to be fully driven by the aggregated consumer peak demand. The aggregated consumer peak demand, also called coincident peak demand, is commonly considered to be the main cost driver of the network (Abdelmotteleb et al., 2017; Baldick, 2018; Pérez-Arriaga et al., 2017). The assumption that no grid costs are sunk could be interpreted as a context in which the network is being built up or a fully amortised network is operating near its limits and needs to be expanded to accommodate strong load-growth.

In Table 15, the capacity of the batteries installed per active consumer is shown for the different distribution network tariff designs. Again, sensitivity analysis regarding the investment costs of the batteries is conducted. The benchmark network tariff design is again the central planner. In this case, fixed network charges do not replicate the outcome of the central planner anymore. Namely, with fixed network charges, active consumers are not incentivised to adjust their electricity withdrawal or injection patterns and thus to limit the incurred network cost. A fully informed central planner who can decide unilaterally on behalf of the consumers on how many batteries to install and how to operate them in order to obtain the lowest system costs is the first best outcome.

[37] The self-consumption rate (SCR) is calculated as in Eq. 8 in Quoilin et al. (2016): the total solar electricity generated plus the total battery electricity output minus the total electricity injected in the grid and the total battery electricity input over the total solar electricity generated. $SCR_i = \frac{\sum_t^T(is_i * \mathrm{SY_{t,i}} - qi_{t,i} + qbout_{t,i} - qbin_{t,i})}{\sum_t^T(is_i * \mathrm{SY_{t,i}})}$. In the same paper, it is stated that self-consumption rates without batteries vary between 30% and 37%, thus agreeing with the value in this example.

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In reality, however, there is no central planner. Instead, consumer decisions are driven by price signals, in this case network tariffs.

Again the results are split up in three parts to single out the interaction between investment in solar PV and batteries by active consumers. Similarly, first, it is assumed that there is no possibility for the active consumer to invest in solar PV. Second, the active consumer is free to install solar PV up to 5 kWp if this investment lowers its costs to fulfil its electricity needs. Third, it is assumed that the active consumer has a 5 kWp installation at its premises.

Table 15: Battery and solar PV investment per active consumer for the different network tariff designs under different investment cost assumptions for batteries and interaction with solar PV investments. All grid costs are assumed to be driven by the aggregated consumer peak demand.

Distribution network tariff design		Benchmark – central planner	Capacity-based [€/kW]	Volumetric Net-purchase [€/kWh]	Volumetric Bi-directional [€/kWh]
Investment cost batteries		Battery installed per active consumer [kWh] / PV in brackets [kWp]			
No PV installed, only batteries can be invested in by the active consumers	350 €/kWh	4.4 (0)	2.7 (0)	0 (0)	0 (0)
	300 €/kWh	4.4 (0)	2.7 (0)	0 (0)	0 (0)
	250 €/kWh	5.5 (0)	3.3 (0)	0 (0)	0 (0)
	200 €/kWh	6.2 (0)	3.7 (0)	0 (0)	0 (0)
	150 €/kWh	6.2 (0)	3.7 (0)	0 (0)	0 (0)
	100 €/kWh	6.2 (0)	3.7 (0)	0 (0)	0 (0)
Batteries and PV can be installed in by the active consumers	350 €/kWh	4.4 (0)	2.7 (0)	0 (5)	0 (0.7)
	300 €/kWh	4.4 (0)	2.7 (0)	0 (5)	0 (0.7)
	250 €/kWh	5.5 (0)	3.3 (0)	0 (5)	0 (0.7)
	200 €/kWh	6.2 (0)	3.7 (0)	0 (5)	0 (0.7)
	150 €/kWh	6.2 (0)	3.7 (0)	0 (5)	0.6 (0.7)
	100 €/kWh	6.2 (0)	3.7 (0)	4.7 (5)	2.2 (0.7)
Active consumer has a 5 kWp solar PV, batteries can be invested in	350 €/kWh	4.6 (5)	2.8 (5)	0 (5)	0 (5)
	300 €/kWh	4.8 (5)	2.8 (5)	0 (5)	0 (5)
	250 €/kWh	5.1 (5)	3.0 (5)	0 (5)	0 (5)
	200 €/kWh	5.7 (5)	3.1 (5)	0 (5)	4.9 (5)
	150 €/kWh	5.7 (5)	3.2 (5)	0 (5)	4.9 (5)
	100 €/kWh	7.3 (5)	4.2 (5)	4.7 (5)	13.3 (5)

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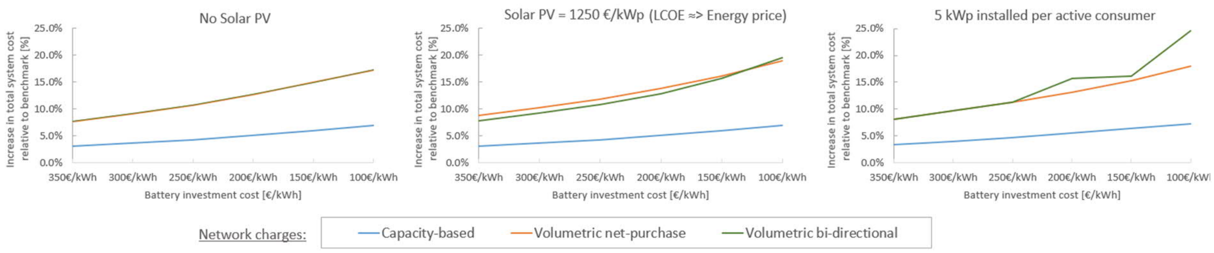

Figure 17: Increase in total system costs for the three network tariff structures when compared with a central planner. Sensitivity for three different assumptions regarding solar PV adoption and the investment cost of storage.

Figure 17 shows the impact on the total system costs for the different distribution network tariff designs. Again, the results are split up for the three cases of solar PV investment, and the results are shown relative to the benchmark.

Four observations are derived from Table 15 and Figure 17. First, under capacity-based charges, batteries are always under-incentivised when all grid costs are driven by the aggregated peak demand. More striking, when comparing these results with the results in Table 14, it can be seen that batteries with a lower capacity are installed than in the case grid costs are assumed sunk even though they are more useful from a system perspective. This can be explained as follows. Under the grid cost assumption, each investment in batteries by active consumers increases the value of additional investment in batteries until a certain point of saturation. This happens as, by each investment in batteries, the network tariff needs to increase in order to recuperate all network costs which remain the same. Thus, the business case of batteries (and solar PV) improves with increasing DER adoption. Saturation occurs when it becomes very costly to lower individual network charges, e.g. further reduce the individual peak demand when it is already significantly lowered due to a certain investment in batteries. This ''race-to-the-bottom'' effect or non-cooperative behaviour is captured by the modelling formulation.[38] On the other hand, if grid costs are assumed to be driven by the aggregated peak demand and the network tariff in place adequately targets the network cost driver, an investment in batteries by active consumers can decrease the value of additional investment in DER. This effect is however ambiguous. Namely, each additional investment in batteries can lower the total grid costs. But at the same time, the grid charges paid by the active consumers will decrease as well. If the decrease in grid charges paid by the active consumer due to the adoption of batteries is lower in magnitude than the decrease in the total grid costs caused by their investment in batteries, all grid costs can be recuperated with a lower network tariff. In that case, an investment in batteries will decrease (''cannibalise'') the incentive to install additional battery capacity.[39] On the other hand, if the decrease in grid charges paid by the active consumer due to the adoption of batteries is higher than the magnitude of the decrease their investment caused on the total grid costs, the network tariff needs to increase to recuperate all grid costs. In this case, the same but weakened ''race-to-the-bottom'' effect as under the sunk grid assumption occurs.

[38] Its significance is mostly a function of the proportion of active consumers and the attractiveness of DER investments relative to the network tariff structure and the magnitude of its coefficients.

[39] Similarly, as each investment in solar PV lowers the price of energy around noon and thus decreases the incentive to install more solar PV as described in Hirth (2013).

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The second observation is that not only batteries are under-invested in; active consumers also do not operate batteries in a way that their operation would lead to the lowest grid costs possible given the installed battery capacity. This is illustrated in the example shown in Figure 18; the results are shown for the run in which we assume that 5 kWp solar PV is installed by the consumer and batteries cost 100 €/kWh. It is clear that under capacity-based charges, the active consumers flatten their profile in order to lower the grid charges to be paid (2nd row - left graph). However, it is the aggregated demand profile of both active and passive consumers that drives the grid costs. The aggregated profile is also shown in Figure 18 (2nd row –right graph). It could be said that active consumers operating their battery under capacity-based charges are uninformed about the aggregated demand.[40] As such, the reduction of the aggregated peak demand is limited. Under the central planner approach, the active consumers significantly lower their demand at the time that the passive consumers have their peak. As a result, the aggregated peak, the one that really matters, is minimised.

In this numerical example, only two consumer groups are modelled: active and passive consumer. Each consumer group is represented by one profile, and the profiles are coincident. In reality, many individual profiles exist, and these will not all be coincident. The assumption of coincident profiles can be interpreted as capacity-based charges which are very carefully implemented, e.g. the capacity is only considered during certain months or even only during moments of the days within these months that the local system peak is expected to take place. More discussion on the implementation of capacity-based charges can be found in Passey et al. (2017) and Hledik (2014). In Appendix B, results are shown for three non-coincident consumer profiles. The results show that all observations remain the same for that setup, except for the fact that the performance of capacity-based network charges in terms of the reduction of system costs is overestimated with coincident consumer profiles. This overestimation mainly occurs when batteries are expensive and thus smaller battery capacities are installed. If higher battery capacities are installed, the individual peaks will be flattened over multiple time-steps thus possibly also during the time steps other consumers have their peak demand. As a result, also the aggregated consumer peak will decrease to a certain extent.

[40] Capacity-based network charges would have the same outcome as the central planner in the case that all consumers are active and they all have exactly the same electricity demand profile. This is also verified with the model.

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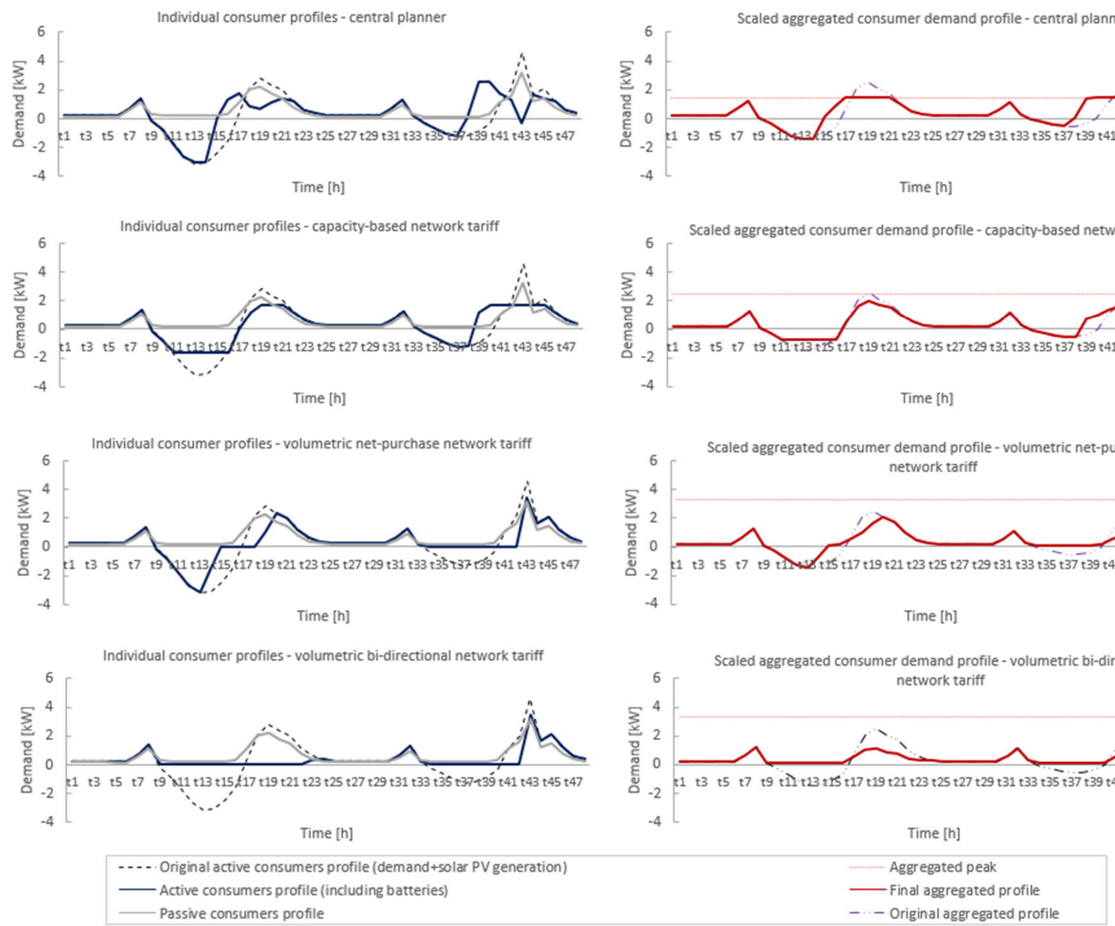

Figure 18: Reactions of active consumers to the different network tariff design and their impact on the aggregated load profile and peak. Assumption: 5 kWp solar PV already installed by the active consumer and battery investment cost of 100 €/kWh.

The third observation is that the two network tariff designs that incentivise self-consumption do not lead to investment in batteries if there is no solar PV installed by the active consumer or when there is solar PV installed, but batteries are relatively expensive. In other words, these network tariff designs block the business case of storage when not coupled with electricity generation behind the meter. Figure 17 shows that because of the fact that no batteries are installed, the system costs are significantly higher than in the central planner case.

Similar as in the case grid costs are assumed sunk, the fourth observation is that the two network tariff designs that incentivise self-consumption are shown to lead to significant investment in batteries if there is solar PV installed by the active consumer and batteries are relatively cheap. However, the investment in batteries does not result in a lower system cost as can be seen from Figure 17. Instead, the opposite occurs. The system cost increases relative to the benchmark. Figure 18 illustrates what happens. Indeed, the active consumers use the battery to increase self-consumption; under volumetric network charges with net-purchase 57.8 % of the electricity generated by solar PV is self-consumed for this example. This percentage increases further for bi-directional volumetric charges as also can be deducted from Figure 18, the self-consumption rate

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attained is 80.8 %.[41] However, the batteries are not operated in a way that their functioning leads to a lower aggregated peak demand. Instead, the batteries are used to store as much self-produced electricity as possible until it is fully charged. After, the battery is used to fulfil the demand of the active consumers instead of grid supplied electricity. The discharging goes on until a point in time that the batteries are fully discharged. Looking at Figure 18, for this example, the batteries are fully discharged just before the time steps when aggregated peak demand is near its maximum. As a result, the aggregated peak demand decreases only very slightly.

Figure 19 summarises observations 1, 2 and 4 and further clarifies what happens regarding the total system cost for the example shown in Figure 18. The first vertical bar represents the baseline scenario, the case that no active consumer invests in DER. The proportions of the grid costs, energy retailer costs and taxes and levies are those as shown in Table 12. The next vertical bar represents the most optimal trade-off between the grid costs, retailer energy costs, solar PV and batteries for the given parameter settings. This optimal trade-off is the result of the central planner. This mix lowers the sum of the interacting components of the electricity bill to a total system cost which is 14 percentage points lower than the baseline.[42] In the example, capacity-based charges, also lead to a mix which lowers the total system costs relative to the baseline, however, not as much as the central planner. Mainly due to an under-incentive to invest in batteries and sub-optimal operational signals, the grid costs are not decreased as much as would be optimal, as discussed in observations 1 and 2. Volumetric network tariffs with net-purchase lead to a total system cost with around the same value as the baseline, even though the composition of the different components is very different. Some batteries are installed, less than optimal, and they are not operated in a way that the grid costs are decreased. Interestingly, for this example, volumetric charges with bi-directional charges lead to a system which is more expensive than the baseline case without any DER investment. An overinvestment in batteries by the active consumers occurs. The active consumers are incentivised to increase self-consumption to a level which is not cost-efficient from a system point of view under the given assumptions.

[41] The self-consumption rates under the central planner and capacity-based charges are respectively 40.6 % and 43.4% for this example.

[42] Taxes and levies are assumed to be invariable and recovered through a fixed charge which does not distort the decisions of consumers.

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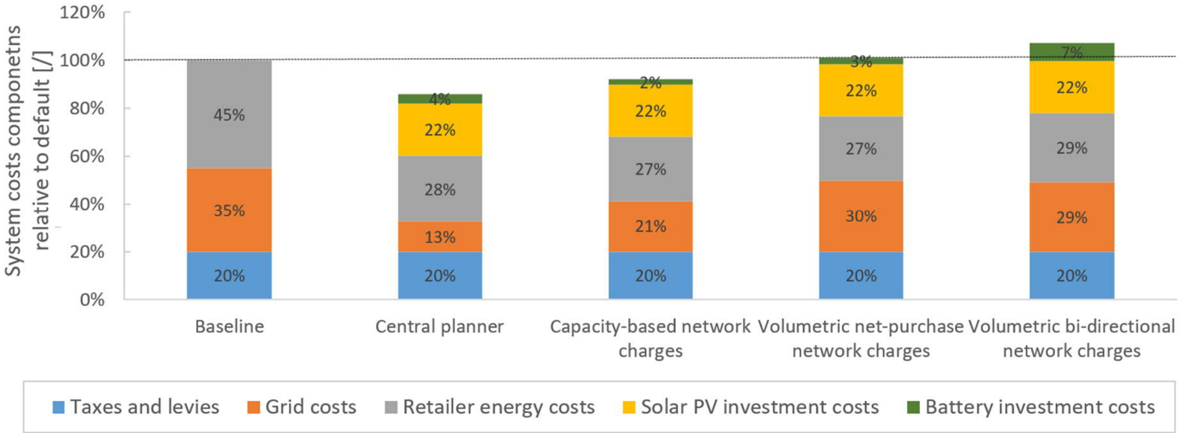

Figure 19: System costs and its components for the different network tariff designs. Assumption: 5 kWp solar PV already installed by the active consumer and battery investment cost of 100 €/kWh.

6.5.3 The impact of time-varying energy prices

In the previous two sections, the focus was laid on the design of the distribution network tariff design. It was shown that the network tariff design has an impact on the business case for storage and whether the business case is aligned with overall system benefits. To single out the impact of distribution network tariff design, we assumed that the energy price was constant in time. However, besides network tariff design, another important driver for battery adoption are time-varying energy prices; households can arbitrage energy prices with batteries. Different papers, e.g. Ren et al. (2016) and Erdinc et al. (2015), show with case studies that a battery system creates greater savings for a household if energy prices are time-varying instead of flat.

In this section, we introduce two TOU energy pricing schemes besides the flat retailer energy prices. In the previous sections, a constant retailer energy price of 0.08 €/kWh is assumed. Figure 20 shows the two newly introduced options. The TOU1 profile is 'solar PV friendly' as during hours that solar PV is producing, an energy price is charged which is slightly higher than the flat energy charge. The TOU2 profile charges relatively high prices during the evening when consumer demand is expected to peak and charges a relatively low price during the hours that solar PV is producing a lot. The TOU2 profile is less 'solar PV friendly' but might induce battery investment due to significant relative changes in the energy price between the different periods. These daily energy price patterns are used as representative for the year. To be able to compare results among the three energy price profiles, the TOU1 and TOU2 profile are scaled to make sure that in the baseline scenario (no DER) the weighted average energy price per consumer type is equal over the different energy price profiles. Also, for the runs for which the PV investment is forced, the difference in avoided energy costs due to solar PV adoption with the different TOU energy price schemes are corrected for to be able to compare the results with flat retailer energy prices.

Please note that energy prices remain considered exogenous, i.e. more solar PV or battery adoption has no impact on the retailer energy prices. These results should therefore be interpreted carefully. They can be interpreted in the context of a specific area with high DER penetration which is part of

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a very large power system over which as a whole the DER penetration is a lot more modest. This assumption can be relaxed in future work.

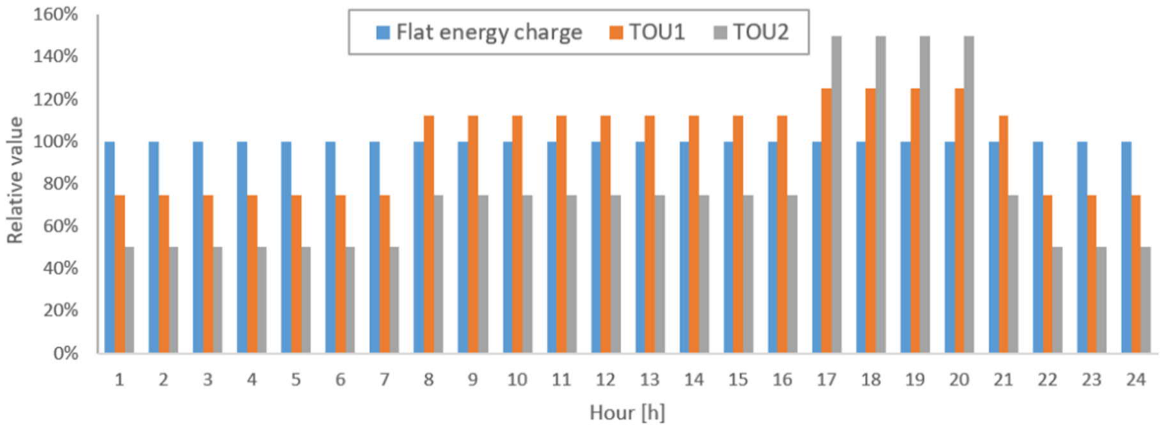

Figure 20: Three energy price schemes.

In Table 16, the results for the battery capacity installed per active consumer are shown for the different battery investment costs, distribution network tariff designs and energy price schemes. We assume that all grid costs are driven by the aggregated peak demand. We do three observations. First, when comparing the results in Table 16 with the results in Table 15, we see that indeed the battery capacity installed by the active consumers remains the same or in most cases increases under the TOU energy prices when compared to flat energy prices. This statement holds for the benchmark and the three evaluated distribution network tariff designs. Second, when comparing the two TOU energy price schemes, the TOU2 energy price scheme results in the highest increase in battery capacity installed for this numerical example. Third, interestingly, still no batteries are installed under the network tariffs that incentivise self-consumption if not combined with the adoption of solar PV. Even though with time-varying energy prices there is the additional opportunity to arbitrage the energy prices.

By including TOU energy prices, not only the grid costs can be decreased due to battery adoption but also the retailer energy costs for active consumers can be lowered due to gains from arbitrage. Looking at the system-level, energy arbitrage by active consumers can have a significant impact on the wholesale energy market. However, because of the fact that the energy prices are not endogenous in the model, it cannot be easily assessed how the arbitrage actions of the active consumers would affect the wholesale energy prices. An extension of the modelling approach is needed. Whatsoever, what is clear is that imperfect network tariff design obstructs optimal energy arbitrage strategies. A consumer, when deciding about the adoption and operation of storage will look at the possible reduction in her final electricity bill, instead of at each separate cost component (network charges, energy costs and taxes and levies) in isolation. As a result, the interaction between network charges and energy prices has an impact on the business case of storage but also on the potential welfare gains from introducing time-varying instead of flat energy prices to residential consumers.

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Table 16: Battery and solar PV investment per active consumer for the different network tariff designs and energy pricing schemes under different investment cost assumptions for batteries and interaction with solar PV investments. All grid costs are assumed to be driven by the aggregated peak demand.

Distribution network tariff design		Benchmark – central planner		Capacity-based [€/kW]		Volumetric Net-purchase [€/kWh]		Volumetric Bi-directional [€/kWh]	
Energy price		TOU1	TOU2	TOU1	TOU2	TOU1	TOU2	TOU1	TOU2
Investment cost batteries		Battery installed per active consumer [kWh] / PV in brackets [kWp]							
No PV installed, only batteries can be invested in by the active consumers	350 €/kWh	4.6 (0)	6.1 (0)	2.8 (0)	3.7 (0)	0 (0)	0 (0)	0 (0)	0 (0)0
	300 €/kWh	5.5 (0)	6.2 (0)	3.3 (0)	3.7 (0)	0 (0)	0 (0)	0 (0)	0 (0)
	250 €/kWh	6.2 (0)	7.4 (0)	3.7 (0)	4.5 (0)	0 (0)	0 (0)	0 (0)	0 (0)
	200 €/kWh	6.2 (0)	11.0 (0)	3.7 (0)	6.6 (0)	0 (0)	0 (0)	0 (0)	0 (0)
	150 €/kWh	6.8 (0)	12.4 (0)	4.6 (0)	7.4 (0)	0 (0)	0 (0)	0 (0)	0 (0)
	100 €/kWh	6.8 (0)	13.5 (0)	6.1 (0)	8.1 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Batteries and PV can be installed in by the active consumers	350 €/kWh	4.7 (0.8)	6.1 (0)	2.8 (0.8)	3.7 (0)	0 (5)	0 (1.2)	0 (0.7)	0 (0.5)
	300 €/kWh	5.5 (0.7)	6.2 (0)	3.3 (0.7)	3.7 (0)	0 (5)	0 (1.2)	0 (0.7)	0 (0.5)
	250 €/kWh	6.1 (0.4)	7.4 (0)	3.6 (0.4)	4.5 (0)	0 (5)	0.3 (1.2)	0 (0.7)	0.1 (0.5)
	200 €/kWh	6.2 (0)	11.0 (0)	3.7 (0)	6.6 (0)	0 (5)	3.8 (4.1)	0.0 (0.7)	0.6 (0.7)
	150 €/kWh	7.6 (0)	12.4 (0)	4.6 (0)	7.4 (0)	0.3 (5)	4.9 (5)	1.7 (1.2)	7.4 (3.1)
	100 €/kWh	10.1(0.5)	13.5 (0)	6.1 (0.5)	8.1 (0)	4.9 (5)	9.4 (4.3)	11.8(4.5)	9.8 (3.9)
Active consumer has a 5 kWp solar PV, batteries can be invested in	350 €/kWh	4.8 (5)	5.7 (5)	2.8 (5)	3.1 (5)	0 (5)	0 (5)	0 (5)	4.9 (5)
	300 €/kWh	5.2 (5)	5.7 (5)	3.0 (5)	3.1 (5)	0 (5)	0 (5)	0 (5)	4.9 (5)
	250 €/kWh	5.7 (5)	7.3 (5)	3.1 (5)	3.7 (5)	0 (5)	4.7 (5)	4.9 (5)	6.1 (5)
	200 €/kWh	5.7 (5)	10.3 (5)	3.2 (5)	6.0 (5)	0 (5)	4.9 (5)	4.9 (5)	8.9 (5)
	150 €/kWh	7.3 (5)	11.9 (5)	3.9 (5)	6.5 (5)	0.3 (5)	4.9 (5)	4.9 (5)	13.3 (5)
	100 €/kWh	10.3 (5)	15.0 (5)	6.0 (5)	10.2 (5)	4.9 (5)	8.9 (5)	13.3 (5)	13.3 (5)

6.5.4 Peak-coincident network prices: approximating the central planner outcome

In the previous subsection, it is shown that none of the evaluated distribution network tariffs can replicate the outcome of the central planner. However, the evaluated network tariff designs are rather simple. In the literature, it is discussed that so-called critical peak-pricing or coincident peak-pricing can reproduce ideal incentive properties for consumers (see e.g. Abdelmotteleb et al.

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(2017), Baldick (2018) and Pérez-Arriaga et al. (2017)). In this work, we test what happens if we allow the upper-level regulator to set such time-varying network charges. Figure 21 shows the resulting peak-coincident network charges for the numerical example with the three energy prices schemes. The results are shown for the case we assume that the active consumers have 5 kWp solar PV installed and the battery investment costs are 250 and 100 €/kWh.

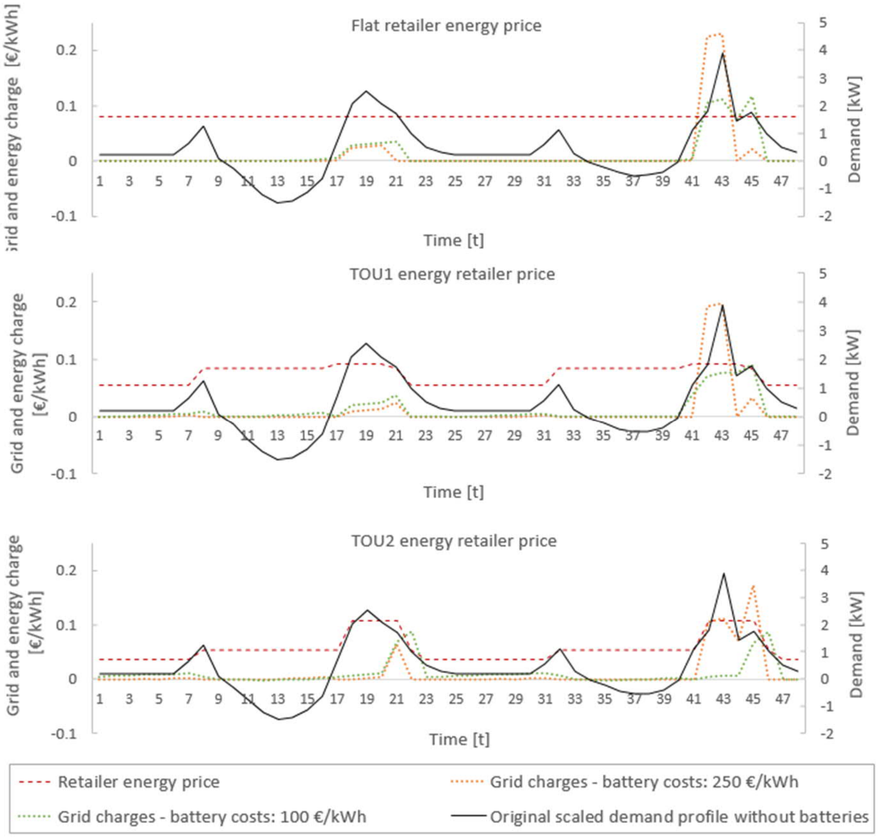

Figure 21: Examples of peak-coincident network prices for the case 5 kWp is installed by the active consumers. Sensitivity for the battery investment costs of 250 and 100 €/kWh.

As expected, it can be seen from Figure 21 that this more advanced network tariff exhibits peak prices at the time steps that the aggregated demand peaks and that network prices are equal to zero when the aggregated demand is rather low.[43] Additionally, it is shown that the network charges are a function of the investment cost of the batteries and the energy price scheme in place. Overall, the lower the battery investment cost, the wider but, the less steep the network peak prices. The width has to do with the fact that if batteries are cheaper and thus higher capacities are adopted, the

[43] The peak-coincident network charges shown in 7 are obtained using a two-step process. First, the MPEC is solved. After solving the MPEC, the lowest possible system costs (the objective of the upper-level) is known. However, the network charges computed are not unique. Namely, the upper-level regulator can arbitrarily increase the time-varying network charge at time-steps that the elasticity of the consumers is very low without changing the obtained value of the objective function. However, these arbitrary choices for the upper-level do have a distributional impact for the lower level consumers. Therefore, a second solution step was added. The MPEC remains exactly the same except for one constraint and the objective function. One constraint is added which states that the total system cost is forced to be equal to the minimal total system cost obtained in step one. The objective function of the upper-level changed to a minimisation the sum of the coefficients of the network charges. As such, a unique solution is obtained for the network charges without room for arbitrary choices of the upper-level regulator.

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number of time steps increases in which the aggregated demand reaches its maximum. During all these time steps a network price signal is needed. The decreasing steepness of the peak has to do with the fact that with cheaper batteries a less strong incentive is needed to reach the optimal outcome.[44] If the peak price would be steeper, too many batteries could be invested in and vice-versa. Further, it can be seen that the network charges adjust with the energy prices scheme in place in order to send an adequate aggregated price signal to the consumers.

For this numerical example, the outcome obtained by these peak-coincident network charges in terms of battery investment and the total system cost is exactly the same or less than 1 % higher than under the central planner.[45] Overall, these results suggest that a more advanced network tariffs as formulated in this paper can approximate the outcome of a first-best outcome closely. A formal proof of how close the approximation is as a function of the parameters is out of the scope of this paper.

Even though these results for peak-coincident network charges are very promising, it should be understated that they hinge upon the assumption that the upper-level regulator has full information about which consumers are active and how these active consumers will respond to a certain network price signal. In reality, there persists an information asymmetry between the regulator and the actions of consumers. It goes without saying that this asymmetry complicates implementation of this optimal network tariff design.

6.6 Conclusion and policy implications

We use a game-theoretical model to analyse whether different distribution network tariff designs align the business case of residential electricity storage, in the form of batteries, with overall wider system benefits. Three different network tariff designs are evaluated: capacity-based charges, net-purchase volumetric network charges and bi-directional volumetric network charges. Capacity-based network tariffs incentivise consumers to lower their individual peak demand. The two other network tariff designs result in a difference between the value of on-site generated electricity that is self-consumed and electricity that is directly injected back into the network. As such, these network tariff design incentivise self-consumption. We compare the outcome of the game-theoretical model for the different network tariff designs with a first-best central planner solution. Besides network tariff design, another important driver for battery adoption is time-varying retailer energy prices. Therefore, also the impact of time-varying energy prices on battery adoption and the interaction with distribution network tariff design is investigated.

We found that the business case of batteries and overall system benefits are not always aligned. In one extreme, the case that most grid costs are sunk and little future grid investment is expected, the evaluated network tariffs mostly over-incentivize battery adoption. In this case, network costs are simply transferred from active to passive consumers, and each investment in batteries by active

[44] The total costs spend on batteries by the active consumer under-time varying prices, which equals the product of the battery capacity installed with the investment cost, decreases with decreasing battery costs.

[45] There are two exceptions, for the scenario when battery costs are 150€/kWh and 100 €/kWh and no investment in solar PV is assumed under TOU2 energy prices, the difference in total system costs is 2.2 and 4.0% respectively. Also, the installed battery capacities differ slightly.

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consumers increases the (private) value of additional investment in batteries. From a grid perspective, there is little need for batteries and the main exercise is to find an as little as possible distortive network tariff design which remains acceptable in terms of distributional impacts. Examples can be found in e.g. Pérez-Arriaga et al. (2017), Pollitt (2018) and Wolak (2018): differentiated fixed network charges are not recovering all sunk grid costs through the electricity bill. Schittekatte and Meeus (2018) show that spreading the grid costs over capacity-based charges, volumetric charges and fixed charges can also mitigate the induced distortions.

After, the other extreme is investigated; the situation when still many grid investments have to be made, and the future grid costs are driven by the growing aggregated peak demand of consumers. It is shown that in that situation the tested network tariff designs will not only give an inadequate investment signal to the consumers, also will the consumers operate their installed batteries sub-optimally from a grid point of view. If consumer electricity demand profiles are rather homogeneous, batteries are under-invested by capacity-based charges. If consumer electricity demand profiles are heterogeneous, consumers will lower their individual demand which will have little effect on the system peak demand; a similar dynamic as in the sunk grid cost scenario occurs. With a network tariff design that encourages self-consumption, the business case of storage is unrightfully negatively impacted when the batteries are not coupled with onsite generation such as solar PV. Oppositely, when active consumers combine solar PV with cheap batteries or grid costs are high, an over-investment in batteries can result under the network tariff designs that encourage self-consumption. The batteries are fully charged with self-generated solar PV to increase self-consumption, but it can happen that by the time the system peak demand occurs, the batteries are already fully discharged again. In that case, a high capacity of batteries is installed, but they do not contribute to overall grid costs savings. It should be noted that energy losses in the distribution network or the cost of bi-directional flows are omitted in the presented analysis.[46] When self-consumption increases, there is less electricity exchange between the active consumers and the grid and bi-directional flows are reduced. More elaborated grid costs functions could be experimented with in future work.

Time-of-use energy prices instead of flat energy prices are shown to improve the business case for residential storage for all evaluated network tariff designs. With time-of-use energy prices, the active consumers can use their batteries to arbitrage energy prices on top of lowering their network charges. However, imperfect network tariff designs can impact the optimal energy arbitrage strategies from a system point of view. To quantitatively assess this effect, an extension of the presented model with endogenous wholesale energy prices is necessary. However, what is clear is that distribution network tariff design and different possible retailer energy price schemes should not be evaluated in isolation. Both interact as a consumer reacts to their aggregate. Even more difficulties can be expected when accounting for taxes and levies in the electricity bill which are left out in this analysis.

Overall, in a high future grid cost scenario, a more advanced network tariff design is needed to correctly align the business case of residential storage and wider system benefits. Without a more

[46] As a reference, Costa-Campi et al. (2018) describe that energy losses in Spain in 2012 represented 8.9% of the total energy injected into the grid.

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advanced network tariff design, it is not possible to fully unlock flexibility from the consumers-side and efficiently coordinate grid charges and energy prices signals. It is shown that peak-coincident network prices, which exhibit strong peak prices at times when there are system demand peaks, give optimal or near-optimal results. Baldick (2018) explains that such types of tariffs are already used for transmission grid prices in for example ERCOT and Great-Britain. However, such distribution network tariff is hard to implement as they should have a very fine locational and temporal granularity. Peak prices could differ from one feeder to another and would have to be announced ex-ante or accounted for ex-post. If they are announced ex-ante, it could happen that the expected peak differs from the realized peak. If they are accounted for ex-post, consumers' bills could become unpredictable. Also, to estimate the magnitude of the coefficients of the peak charges is a hard job. Possibly time-of-use (TOU) network charges could be a good compromise between efficiency and implementation difficulty.

Finally, other mechanisms could complement network tariff design to unlock consumer flexibility in terms of batteries adoption and operation. Examples are flexibility markets for system services (also referred to as markets for ancillary services) in which the DSO and/or TSO are the buyers of these services as described in Hadush and Meeus (2018). Both local congestion management or system balancing services can be procured. In these markets, aggregators can bundle DER resources. However, similar as with the introduction of time-of-use energy prices, it can also be expected that there will be an interaction between the network tariff design and the markets for the delivery of such services. This interaction deserves further attention when designing flexibility markets.

It should be added that an important driver for the business case of residential electricity storage is left out the analysis, namely resilience. In areas where the electricity supply from the central grid is not very reliable, this can be an important driver. This driver is however hard to quantify. Also, by including an endogenous energy market in the model, more insight can be gained about how the interaction of time-varying energy prices and network tariffs impacts welfare. Govaerts et al. (2019) apply a similar model to analyse the spill-over effects of different distribution network tariffs across multiple countries.

Finally, the game-theoretical approach applied in this work is highly stylised. For example, battery degradation is not taken into account. Battery degradation has shown to be an important cost for batteries which can also impact the operational strategy (Sidhu, Pollitt, & Anaya, 2018; Thompson, 2018; Uddin, Gough, Radcli, Marco, & Jennings, 2017). Also, a constant C-rate (max. output over max. energy capacity) of the battery has been assumed. Different C-rates could lead to different business cases and uses for the battery as also shown in Schittekatte et al. (2016) and Schill et al. (2017). Besides battery storage, demand-side management (DSM) and smart charging of an electric vehicle is another way to do peak shaving, increase self-consumption or arbitrage energy prices. For example, Erdinc et al. (2015) show how the optimal sizing of batteries is impacted when considering the demand response possibilities and Hoarau and Perez (2018) discuss the impact of smart EV charging on battery adoption. These points offer possibilities to extend the presented analysis.

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6.8 Appendix 6.A: the complete modelling formulation

6.8.1 A.1 Overview of the used sets, parameters and variables

Sets

i : 1,..,N: Consumers types
t: 1,..,T: Time steps with a certain granularity

Parameters

Upper-level

SunkGridCosts: Sunk annualised grid costs, scaled per average consumer [€]
IncrGridCosts: Incremental annualised grid cost per kW increase/decrease of the coincident peak demand/injection, scaled per average consumer [€/kW]
DPeak: (Default) coincident peak demand before investment in DER by active consumers, scaled per average consumer [kW]
WF: Weighting factor, indicating the inaccuracy in the network cost driver [-]
NM: Factor indicating whether net-metering (1) or no net-metering (0) or bi-directional volumetric charges (-1) are in place [-]
PC_i : Proportion of consumer type i
TotalOtherCosts: all other costs paid through the electricity bill, e.g. policy costs, annualised and scaled per consumer [€]
BGC_i : Baseline volumetric grid charges paid before investment in DER for consumer type i [€]
Cap_i: Cap on the increase of grid charges paid for consumer type i [%]

Lower level

WDT: Scaling factor to annualise, dependent on length of the used time series and time step [-]
DT: time step, as a fraction of 60 minutes [-]
$D_{t,i}$: Original demand at time step t of agent i [kW]
MS_i : Maximum solar capacity that can be installed by agent i [kW]
MB_i : Maximum battery capacity that can be installed by agent i [kWh]
$SY_{t,i}$: Yield of the PV panel at time step t of agent i [kWh/kW_{peak}]
EBP_t: Energy price to be paid by agent for buying from the grid [€/kWh]
ESP_t: Energy price received by agent for buying from the grid (feed-in tariff) [€/kWh]
AICS: Annualised investment cost solar PV [€/kW_{peak}]
AICB: Annualised investment cost battery [€/kWh]
BDR: Ratio of max power output of the battery over the installed energy capacity [-]
BCR: Ratio of max power input of the battery over the installed energy capacity [-]
EFD: Efficiency of discharging the battery [%]
EFC: Efficiency of charging the battery [%]
LR: Leakage rate of the battery [%]
SOC_0: Original (and final) state of charge of the battery [kWh]
OtherCosts: other costs paid through the electricity bill, e.g. policy costs [€]
$PrDSM_i$: Max. percentage of the demand at any time step that can be shifted by DSM [%]
$CDSM_i$: Cost of DSM per kWh shifted [€/kWh]

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Variables

UL decision variable

vnt : Volumetric network tariff [€/kWh]
cnt: Capacity network charge [€/kW$_{peak}$]
fnt: Fixed network charge [€/connection]
cpp_t: Time-varying network charge [€/kWh] (free variable)
$CoincidentPeak$: The coincident (aggregated) peak demand after optimisation (highest absolute of value of the positive/negative coincident peak), scaled per average consumer [kW]
$CPeakDemand$: Positive coincident peak demand after optimisation, scaled per average consumer [kW]
$CPeakInjection$: Negative coincident peak demand after optimisation, scaled per average consumer [kW]
$TotalGridCost$: Total annualised grid cost, scaled per average consumer [€]
$TotalDERcosts$: Total annualised investment cost in DER, scaled per average consumer [€]
$TotalEnergyCosts$: Total annualised energy cost, scaled per average consumer [€]
$TotalDSMCosts$: Total annualised demand side management operational cost, scaled per average consumer [€]

LL decision variable

$GridCharges_i$: Annualised grid charges for agent i [€]
$DERCosts_i$: Annualised investment cost in DER for agent i [€]
$EnergyCosts_i$: Annualised energy cost for agent i [€]
$DSMCosts_i$: Annualised demand side management operational cost for agent i [€]
$qw_{t,i}$: Energy bought at time step t by agent i [kW]
$qi_{t,i}$: Energy sold at time step t by agent i [kW]
$qmax_i$: Peak demand of agent i over the length of the considered time series [kW]
$soc_{t,i}$: State of charge of the battery of agent i at step t [kWh]
$qbout_{t,i}$: Discharge of the battery of agent i at step t [kW]
$qbin_{t,i}$: Power input into the battery of agent i at step t [kW]
is_i: Installed capacity of solar by agent i [kW]
ib_i: Installed capacity of the battery by agent i [kWh]
$uDSM_{t,i}$: Energy increased at time step t by agent i due to DSM (shifted from another time step) [kW]
$dDSM_{t,i}$: Energy decreased at time step t by agent i due to DSM (shifted to another time step) [kW]

6.8.2 A.2. Original optimisation problems

The upper-level problem for a total system cost minimising regulator

Objective function, the minimisation of total system costs:

$$\text{Minimise } TotalGridCosts + TotalDERcosts + TotalEnergyCosts + TotalDSMCosts + \text{TotalOtherCosts} \quad \text{(A.1)}$$

With its components being:

$$TotalGridCosts = \text{SunkGridCosts} + \text{IncrGridCosts} * (\text{DPeak} - \text{WF} * (\text{DPeak} - OPeak)) \quad \text{(A.2)}$$
$$TotalDERcosts = \textstyle\sum_{i=1}^{N} \text{PC}_i * (is_i * \text{AICS} + ib_i * \text{AICB}) \quad \text{(A.3)}$$
$$TotalEnergyCosts = \textstyle\sum_{t=1}^{T}\sum_{i=1}^{N} \text{PC}_i * \left(qw_{t,i} * \text{EBP}_t - qi_{t,i} * \text{ESP}_t\right) * \text{WDT} \quad \text{(A.4)}$$
$$TotalDSMCosts = \textstyle\sum_{t=1}^{T}\sum_{i=1}^{N} \text{PC}_i * \left(dDSM_{t,i}\right) * \text{CDSM}_i * \text{WDT} \quad \text{(A.5)}$$

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Finding the aggregated peak demand in absolute value:

$$CoincidentPeak \equiv Max\{CPeakDemand, CPeakInjection\} \quad (A.6)$$

$$CPeakDemand \equiv Max\left\{\sum_{i=1}^{N} PC_i\left(qw_{t,i} - qi_{t,i}\right) \forall t\right\} \quad (A.7)$$

$$CPeakInjection \equiv Max\left\{\sum_{i=1}^{N} PC_i\left(qi_{t,i} - qw_{t,i}\right) \forall t\right\} \quad (A.8)$$

Cost recovery Eq. of the upper-level (A.9) with a cap on the increase of grid charges of the passive consumer (i2) (A.10):

$$TotalGridcosts = vnt * \sum_{t=1}^{T}\sum_{i=1}^{N} \mathrm{PC}_i * \left(qw_{t,i} - \mathrm{NM} * qi_{t,i}\right) * \mathrm{WDT} + cnt * \sum_{i=1}^{N} \mathrm{PC}_i * qmax_i + \sum_{t=1}^{T}\sum_{i=1}^{N} \mathrm{PC}_i * cpp_t * (qw_{t,i} - qi_{t,i}) * \mathrm{WDT} + fnt \quad (A.9)$$

$$vnt * \sum_{t=1}^{T}\left(qw_{t,'i2'} - \mathrm{NM} * qi_{t,'i2'}\right) * \mathrm{WDT} + cnt * qmax_{'i2'} + CPP_{t,i} * \sum_{t=1}^{T}\sum_{i=1}^{N} \mathrm{PC}_i * (qw_{t,i} - qi_{t,i}) * \mathrm{WDT} + fnt \leq \mathrm{BGC}_{'i2'} * (1 + \mathrm{Cap}_{'i2'}) \quad (A.10)$$

The lower level problem for an electricity cost minimising consumer

Objective function per consumer type i, the minimisation of individual electricity cost:

$$\text{Minimise } GridCharges_i + DERCosts_i + EnergyCosts_i + DSMCosts_i + \text{OtherCharges} \quad (A.11)$$

With:

$$GridCharges_i = \sum_{t=1}^{T}(qw_{t,i} - qi_{t,i} * \mathrm{NM}) * vnt * \mathrm{WDT} + qmax_i * cnt + \sum_{t=1}^{T}(qw_{t,i} - qi_{t,i}) * cpp_t * \mathrm{WDT} + fnt \quad \forall i \quad (A.12)$$

$$DERCosts_i = is_i * \mathrm{AICS} + ib_i * \mathrm{AICB} \quad \forall i \quad (A.13)$$

$$EnergyCosts_i = \sum_{t=1}^{T}\left(qw_{t,i} * \mathrm{EBP_t} - qi_{t,i} * \mathrm{ESP_t}\right) * \mathrm{WDT} \quad \forall i \quad (A.14)$$

$$DSMCosts_i = \sum_{t=1}^{T}\left(dDSM_{t,i}\right) * \mathrm{CDSM_i} * \mathrm{WDT} \quad \forall i \quad (A.15)$$

Constraints (including duals):

$$qw_{t,i} - qi_{t,i} + is_i * \mathrm{SY_{t,i}} + qbout_{t,i} - qbin_{t,i} + dDSM_{t,i} - uDSM_{t,i} - \mathrm{D_{t,i}} = 0 \quad \forall i,t \quad (\mu_{t,i}^{a}) \quad (A.16)$$

$$soc_{1,i} - qbin_{1,i} * \mathrm{EFC} * \mathrm{DT} + (qbout_{1,i}/\mathrm{EFD}) * \mathrm{DT} - \mathrm{SOC_0} = 0 \quad \forall i \quad (\mu_{1,i}^{b}) \quad (A.17)$$

$$soc_{t,i} - qbin_{t,i} * \mathrm{EFC} * \mathrm{DT} + \left(qbout_{t,i}/\mathrm{EFD}\right) * \mathrm{DT} - soc_{t-1,i} * (1 - \mathrm{LR} * \mathrm{DT}) = 0 \quad \forall i, t \neq 1 \quad (\mu_{t\neq1,i}^{b}) \quad (A.18)$$

$$soc_{T,i} - \mathrm{SOC_0} = 0 \quad \forall i \quad (\mu_i^{c}) \quad (A.19)$$

$$\sum_{t=1}^{\mathrm{T \in day}}\left(uDSM_{t,i} - dDSM_{t,i}\right) = 0 \quad \forall i \quad (\mu_i^{d}) \quad (A.20)$$

$$-qmax_i + qw_{t,i} + qi_{t,i} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{a}) \quad (A.21)$$

$$soc_{t,i} - ib_i \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{b}) \quad (A.22)$$

$$qbout_{t,i} - ib_i * \mathrm{BDR} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{c}) \quad (A.23)$$

$$qbin_{t,i} - ib_i * \mathrm{BCR} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{d}) \quad (A.24)$$

$$dDSM_{t,i} - \mathrm{PrDSM_i} * \mathrm{D_{t,i}} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{e}) \quad (A.25)$$

$$-qw_{t,i} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{f}) \quad (A.26)$$

$$-qi_{t,i} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{g}) \quad (A.27)$$

$$-soc_{t,i} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{h}) \quad (A.28)$$

$$-qbout_{t,i} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{i}) \quad (A.29)$$

$$-qbin_{t,i} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{j}) \quad (A.30)$$

$$-dDSM_{t,i} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{k}) \quad (A.31)$$

$$-uDSM_{t,i} \leq 0 \quad \forall t,i \quad (\lambda_{t,i}^{l}) \quad (A.32)$$

$$is_i - \mathrm{MS}_i \leq 0 \quad \forall i \quad (\lambda_i^{m}) \quad (A.33)$$

$$ib_i - \mathrm{MB}_i \leq 0 \quad \forall i \quad (\lambda_i^{n}) \quad (A.34)$$

$$-is_i \leq 0 \quad \forall i \quad (\lambda_i^{o}) \quad (A.35)$$

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$-\,ib_i \ \leq 0$ $\qquad \forall\, i \qquad (\lambda_i^p)$ (A.36)

$-\,qmax_i \ \leq 0$ $\qquad \forall\, i \qquad (\lambda_i^q)$ (A.37)

$\lambda_{t,i}^a, \lambda_{t,i}^b, \lambda_{t,i}^c, \lambda_{t,i}^d, \lambda_{t,i}^e, \lambda_{t,i}^f, \lambda_{t,i}^g, \lambda_{t,i}^h, \lambda_{t,i}^i, \lambda_{t,i}^j, \lambda_{t,i}^k, \lambda_{t,i}^l \ \geq 0$ $\qquad \forall\, t,i$ (A.38)

$\lambda_i^m, \lambda_i^n, \lambda_i^o, \lambda_i^p, \lambda_i^q, \geq 0$ $\qquad \forall\, i$ (A.39)

Eq. (A.37) is noted down for completeness, the constraint is implied by Eq. A.21, A.26 and A.27.

6.8.3 A.3. MPEC reformulation as a MILP

6.8.3.1 A. Method 1 to transform the bilinear products in Eq. A.9: discretisation

Newly introduced sets, parameters and variables

Sets

k: 1...K: Index of auxiliary binaries (b_k^a) to discretise the bilinear product (including vnt) in Eq. (A.9)

l: 1...L: Index of auxiliary binaries (b_l^c) to discretise the bilinear product (including cnt) in Eq. (A.9)

m: 1...M: Index of auxiliary binaries ($b_{m,t}^c$) to discretise the bilinear product (including cpp_t) in Eq. (A.9)

Parameters

δ: Allowed band wherein the grid costs charges can differ from the grid charges collected as a percentage of the total grid costs [%]

Δγ: Step of vnt when discretised [-]

Δ∂: Step of cnt when discretised [-]

Δθ: Step of cpp_t when discretised [-]

M^{Da}: Large scalar used to discretise the bilinear product (including vnt) in Eq. (A.9) [-]

M^{Db}: Large scalar used to discretise the bilinear product (including cnt) in Eq. (A.9) [-]

M_t^{Dc}: Large scalar used to discretise the bilinear product (including cpp_t) in Eq. (A.9) [-]

Variables

b_k^a: Binary variables used to discretise the bilinear product (including vnt) in Eq. (A.9)

b_l^b: Binary variables used to discretise the bilinear product (including cnt) in Eq. (A.9)

$b_{m,t}^c$: Binary variables used to discretise the bilinear product (including cpp_t) in Eq. (A.9)

z_k^a: (Pos.) continuous variables used to represent the bilinear product (including vnt) in Eq. (A.9)

z_l^b: (Pos.) continuous variables used to represent the bilinear product (including cnt) in Eq. (A.9)

$z_{m,t}^c$: (Pos.) continuous variables used to represent the bilinear product (including cpp_t) in Eq. (A.9)

6.8.4 Model transformations

Transformation of the grid cost recovery equality of the upper-level

For easier convergence of the model, the grid cost recovery Equality (A.9) is replaced by two constraints (A.40-41) making sure that the network charges collected from the consumers are within a band (1±δ) of the grid costs to be recovered. In the performed runs δ is set to 0.1%.

$$TotalGridCost * (1 - \delta) - vnt * \sum_{t=1}^{T}\sum_{i=1}^{N} \mathrm{PC}_i * (qw_{t,i} - \mathrm{NM} * qi_{t,i}) * \mathrm{WDT} + \ cnt * \sum_{i=1}^{N} \mathrm{PC}_i * qmax_i + CPP_{t,i} * \sum_{t=1}^{T}\sum_{i=1}^{N} \mathrm{PC}_i * (qw_{t,i} - qi_{t,i}) * \mathrm{WDT} \ + fnt \leq 0 \qquad \text{(A.40)}$$

$$-TotalGridCost * (1 + \delta) + vnt * \sum_{t=1}^{T}\sum_{i=1}^{N} \mathrm{PC}_i * (qw_{t,i} - \mathrm{NM} * qi_{t,i}) * \mathrm{WDT} + \ cnt * \sum_{i=1}^{N} \mathrm{PC}_i * qmax_i + CPP_{t,i} * \sum_{t=1}^{T}\sum_{i=1}^{N} \mathrm{PC}_i * (qw_{t,i} - qi_{t,i}) * \mathrm{WDT} \ + fnt \leq 0 \qquad \text{(A.41)}$$

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Discretising the bilinear products (of two positive continuous variables) to turn the NLP in a MIP

Formulation based on Momber (2015), page 102, Eq. 4.60-4.63. We define:

$$q^{tot} = \sum_{t=1}^{T}\sum_{i=1}^{N} \mathrm{PC_i} * (qw_{t,i} - \mathrm{NM} * qi_{t,i}) * \mathrm{WDT} \quad (A.42)$$

and $vnt = \Delta\gamma * \sum_k 2^{k-1} * b_k^a$ (A.43)

$$qmax^{tot} = \sum_{i=1}^{N} \mathrm{PC_i} * qmax_i \quad (A.44)$$

and $cnt = \Delta\partial * \sum_l 2^{l-1} * b_l^b$ (A.45)

$$q_t^{cpp} = \sum_{t=1}^{T} \mathrm{PC_i} * (qw_{t,i} - qi_{t,i}) * \mathrm{WDT} \quad \forall t \quad (A.46)$$

and $cpp_t = \Delta\theta * \sum_m 2^{m-1} * b_{l,t}^c$ $\forall t$ (A.47)

It follows that:

$$q^{tot} * vnt = q^{tot} * \Delta\gamma * \sum_k 2^{k-1} * b_k^a = \Delta\gamma * \sum_k 2^{k-1} * z_k^a \quad (A.48)$$

$$qmax^{tot} * cnt = qmax^{tot} * \Delta\partial * \sum_l 2^{l-1} * b_l^b = \Delta\partial * \sum_l 2^{l-1} * z_l^b \quad (A.49)$$

$$q_t^{cpp} * cpp_t = q_t^{cpp} * \Delta\theta * \sum_m 2^{m-1} * b_{l,t}^c = \Delta\theta * \sum_m 2^{m-1} * z_{m,t}^c \quad \forall t \quad (A.50)$$

with:

$$z_k^a \geq 0 \quad \forall k \quad (A.51)$$
$$z_k^a \leq \mathrm{M^{Da}} * b_k^a \quad \forall k \quad (A.52)$$
$$q^{tot} - z_k^a \geq 0 \quad \forall k \quad (A.53)$$
$$q^{tot} - z_k^a \leq \mathrm{M^{Da}} * (1 - b_k^a) \quad \forall k \quad (A.54)$$

$$z_l^b \geq 0 \quad \forall l \quad (A.55)$$
$$z_l^b \leq \mathrm{M^{Db}} * b_l^b \quad \forall l \quad (A.56)$$
$$qmax^{tot} - z_l^b \geq 0 \quad \forall l \quad (A.57)$$
$$qmax^{tot} - z_l^b \leq \mathrm{M^{Db}} * (1 - b_l^b) \quad \forall l \quad (A.58)$$

$$z_{m,t}^c \geq 0 \quad \forall m,t \quad (A.59)$$
$$z_{m,t}^c \leq \mathrm{M_t^{Dc}} * b_{m,t}^c \quad \forall m,t \quad (A.60)$$
$$q_t^{cpp} - z_{m,t}^c \geq 0 \quad \forall m,t \quad (A.61)$$
$$q_t^{cpp} - z_{m,t}^c \leq \mathrm{M_t^{Dc}} * (1 - b_{m,t}^c) \quad \forall m,t \quad (A.62)$$

$\mathrm{M^{Da}}$, $\mathrm{M^{Db}}$ and $\mathrm{M_t^{Dc}}$ are well calibrated and $\Delta\gamma$, $\Delta\partial$ and $\Delta\theta$ are chosen to balance precision and computational time. Eq. (A.40-A.41) and further transformed to (A.63- A.64) which is the final form of Eq. (A.8) included in the model formulation

$$TotalGridCost * (1 - \delta) - \Delta\gamma * \sum_k 2^{k-1} * z_k^a + \Delta\partial * \sum_l 2^{l-1} * z_l^b + \sum_t^T\left(\Delta\theta * \sum_m 2^{m-1} * z_{m,t}^c\right) + fnt \leq 0 \quad (A.63)$$

$$-TotalGridCost * (1 + \delta) - \Delta\gamma * \sum_k 2^{k-1} * z_k^a + \Delta\partial * \sum_l 2^{l-1} * z_l^b + \sum_t^T\left(\Delta\theta * \sum_m 2^{m-1} * z_{m,t}^c\right) + fnt \leq 0 \quad (A.64)$$

6.8.4.1 Method 2 to transform the bilinear products in Eq. A.9: strong duality theorem

The strong duality theorem says that if a problem is convex, the objective functions of the primal and dual problems have the same value at the optimum (Castillo, Conejo, Pedregal, García, & Alguacil, 2001). We apply this theorem to the lower-level problem. The objective function of the primal problem is stated in Eq. A.11. The dual objective is derived from (A.11-39) and formulated as follows:

$$\text{Maximise } \sum_{t=1}^{T}(\mu_{t,i}^a * \mathrm{D}_{t,i}) + \mu_{1,i}^b * \mathrm{SOC_0} - \sum_{t=1}^{T} \mathrm{PrDSM_i} * \mathrm{D_{t,i}} * \lambda_{t,i}^e - \mathrm{MS}_i * \lambda_i^m - \mathrm{MB}_i * \lambda_i^n \quad (A.65)$$

Thus it follows that:

$$\sum_{t=1}^{T}(\mu_{t,i}^a * \mathrm{D}_{t,i}) + \mu_{1,i}^b * \mathrm{SOC_0} - \sum_{t=1}^{T}(\mathrm{PrDSM_i} * \mathrm{D_{t,i}} * \lambda_{t,i}^e) - \mathrm{MS}_i * \lambda_i^m - \mathrm{MB}_i * \lambda_i^n = \sum_{t=1}^{\mathrm{T}}(qw_{t,i} - qi_{t,i} * \mathrm{NM}) * vnt * \mathrm{WDT} + qmax_i * cnt + \sum_{t=1}^{\mathrm{T}}(qw_{t,i} - qi_{t,i}) * cpp_t * \mathrm{WDT} + fnt + is_i * \mathrm{AICS} + ib_i * \mathrm{AICB} + \sum_{t=1}^{\mathrm{T}}\left(qw_{t,i} * \mathrm{EBP_t} - qi_{t,i} * \mathrm{ESP_t}\right) * \mathrm{WDT} + \sum_{t=1}^{\mathrm{T}}\left(dDSM_{t,i}\right) * \mathrm{CDSM_i} * \mathrm{WDT} \quad (A.66)$$

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We can reformulate A.66 as:

$$\sum_{t=1}^{T}(qw_{t,i}-qi_{t,i}*\mathrm{NM})*vnt*\mathrm{WDT}+qmax_i*cnt+\sum_{t=1}^{T}(qw_{t,i}-qi_{t,i})*cpp_t*\mathrm{WDT}+fnt=\sum_{t=1}^{T}(\mu_{t,i}^{a}*\mathrm{D}_{t,i})+\mu_{1,i}^{b}*\mathrm{SOC}_0-\sum_{t=1}^{T}(\mathrm{PrDSM_i}*\mathrm{D_{t,i}}*\lambda_{t,i}^{e})-\mathrm{MS}_i*\lambda_i^m-\mathrm{MB}_i*\lambda_i^n-\left(is_i*\mathrm{AICS}+ib_i*\mathrm{AICB}+\sum_{t=1}^{T}(qw_{t,i}*\mathrm{EBP_t}-qi_{t,i}*\mathrm{ESP_t})*\mathrm{WDT}+\sum_{t=1}^{T}(dDSM_{t,i})*\mathrm{CDSM_i}*\mathrm{WDT}\right) \quad (A.67)$$

If we now multiply both sides by $\sum_{i=1}^{N}\mathrm{PC}_i$:

$$\sum_{i=1}^{N}\mathbf{PC}_i*\left(\sum_{t=1}^{T}(\boldsymbol{qw_{t,i}}-\boldsymbol{qi_{t,i}}*\mathbf{NM})*\boldsymbol{vnt}*\mathbf{WDT}+\boldsymbol{qmax_i}*\boldsymbol{cnt}+\sum_{t=1}^{T}(\boldsymbol{qw_{t,i}}-\boldsymbol{qi_{t,i}})*\boldsymbol{cpp_t}*\mathbf{WDT}+\boldsymbol{fnt}\right)=\sum_{i=1}^{N}\mathrm{PC}_i*\left(\sum_{t=1}^{T}(\mu_{t,i}^{a}*\mathrm{D}_{t,i})+\mu_{1,i}^{b}*\mathrm{SOC}_0-\sum_{t=1}^{T}(\mathrm{PrDSM_i}*\mathrm{D_{t,i}}*\lambda_{t,i}^{e})-\mathrm{MS}_i*\lambda_i^m-\mathrm{MB}_i*\lambda_i^n-\left(is_i*\mathrm{AICS}+ib_i*\mathrm{AICB}+\sum_{t=1}^{T}(qw_{t,i}*\mathrm{EBP_t}-qi_{t,i}*\mathrm{ESP_t})*\mathrm{WDT}+\sum_{t=1}^{T}(dDSM_{t,i})*\mathrm{CDSM_i}*\mathrm{WDT}\right)\right) \quad (A.68)$$

We can see that the left-hand side of Eq. A.68 equals the right hand-side of Eq. A.9. Thus, we replace the bilinear terms in the right hand side of Eq. A.9 with the linear expression on the right-hand side of Eq. A.68.[47]

6.8.5 Karush-Kuhn-Tucker (KKT) conditions of the lower level

We derive the KKT conditions of the lower level problem (Eq. A.11-39):

$\mathrm{WDT}*(\mathrm{EBP}_t+vnt+cpp_t)+\mu_{t,i}^{a}+\lambda_{t,i}^{a}-\lambda_{t,i}^{f}=0$		$\forall\, t,i$	(A.69)
$-\mathrm{WDT}*(\mathrm{ESP}_t+\mathrm{NM}*vnt+cpp_t)-\mu_{t,i}^{a}+\lambda_{t,i}^{a}-\lambda_{t,i}^{g}=0$		$\forall\, t,i$	(A.70)
$cnt-\sum_t\lambda_{t,i}^{a}=0$		$\forall\, i$	(A.71)
$\mu_{t,i}^{b}-\mu_{t+1,i}^{b}*(1-\mathrm{LT}*\mathrm{DT})+\lambda_{t,i}^{b}-\lambda_{t,i}^{h}=0$		$\forall\, t\neq\{\mathrm{T}\},i$	(A.72)
$\mu_{T,i}^{b}+\mu_i^{c}+\lambda_{T,i}^{b}-\lambda_{T,i}^{h}=0$		$\forall\, t=\mathrm{T},i$	(A.73)
$\mu_{t,i}^{a}+\frac{\mu_{t,i}^{b}}{\mathrm{EFD}}*\mathrm{DT}+\lambda_{t,i}^{c}-\lambda_{t,i}^{i}=0$		$\forall\, t,i$	(A.74)
$-\mu_{t,i}^{a}-\mu_{t,i}^{b}*\mathrm{EFC}*\mathrm{DT}+\lambda_{t,i}^{d}-\lambda_{t,i}^{j}=0$		$\forall\, t,i$	(A.75)
$\mathrm{CDSM}_i*\mathrm{WDT}+\mu_{t,i}^{a}-\mu_{t\in day,i}^{d}+\lambda_{t,i}^{e}-\lambda_{t,i}^{k}=0$		$\forall\, t,i$	(A.76)
$-\mu_{t,i}^{a}+\mu_{t\in day,i}^{d}-\lambda_{t,i}^{l}=0$		$\forall\, t,i$	(A.77)
$\mathrm{AICS}+\sum_t\mu_{t,i}^{a}*\mathrm{SY_{t,i}}+\lambda_i^m-\lambda_i^o=0$		$\forall\, i$	(A.78)
$\mathrm{AICB}-\sum_t\mu_{t,i}^{b}-\sum_t\lambda_{t,i}^{c}*\mathrm{BDR}-\sum_t\lambda_{t,i}^{d}*\mathrm{BCR}+\lambda_i^n-\lambda_i^p=0$		$\forall\, i$	(A.79)
$qw_{t,i}-qi_{t,i}+is_i*\mathrm{SY}_{t,i}+qbout_{t,i}-qbin_{t,i}+dDSM_{t,i}-uDSM_{t,i}-\mathrm{D}_{t,i}=0$	$\mu_{t,i}^{a} free$	$\forall\, t,i$	(A.80)
$soc_{1,i}-qbin_{1,i}*\mathrm{EFC}*\mathrm{dt}+\frac{qbout_{1,i}}{\mathrm{EFD}}*\mathrm{DT}-\mathrm{SOC}_0=0$	$\mu_{1,i}^{b}\ free$	$\forall\, i$	(A.81)
$soc_{t,i}-qbin_{t,i}*\mathrm{EFC}*\mathrm{dt}+\frac{qbout_{t,i}}{\mathrm{EFD}}*\mathrm{DT}-soc_{t-1,i}*(1-\mathrm{LR}*\mathrm{DT})=0$	$\mu_{t\neq 1,i}^{b}\ free$	$\forall\, t\neq 1,i$	(A.82)
$soc_{T,i}-\mathrm{SOC}_0=0$	$\mu_i^{c}\ free$	$\forall\, i$	(A.83)
$\sum_{t=1}^{T\in day}(uDSM_{t,i}-dDSM_{t,i})=0$	$\mu_i^{d}\ free$	$\forall\, i$	(A.84)
$0\leq qmax_i-qw_{t,i}-qi_{t,i}$	$\perp\ \lambda_{t,i}^{a}\geq 0$	$\forall\, t,i$	(A.85)

[47] $\sum_{i=1}^{N}\mathrm{PC}_i*fnt=fnt$ as each consumer pays the same fixed charge. Also, fnt is a constant for the lower level objective and therefore is subtracted from the right-hand side of Eq. 68 when substituting it with the right hand side of Eq. 9.

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$$0 \leq ib_{\mathrm{i}} - soc_{t,i} \quad \perp \lambda^{b}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.86)$$
$$0 \leq ib_{\mathrm{i}} * \mathrm{BDR} - qbout_{t,i} \quad \perp \lambda^{c}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.87)$$
$$0 \leq ib_{\mathrm{i}} * \mathrm{BCR} - qbin_{t,i} \quad \perp \lambda^{d}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.88)$$
$$0 \leq \mathrm{PrDSM_i} * \mathrm{D_{t,i}} - dDSM_{t,i} \quad \perp \lambda^{e}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.89)$$
$$0 \leq qw_{t,i} \quad \perp \lambda^{f}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.90)$$
$$0 \leq qi_{t,i} \quad \perp \lambda^{g}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.91)$$
$$0 \leq soc_{t,i} \quad \perp \lambda^{h}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.92)$$
$$0 \leq qbout_{t,i} \quad \perp \lambda^{i}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.93)$$
$$0 \leq qbin_{t,i} \quad \perp \lambda^{j}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.94)$$
$$0 \leq dDSM_{t,i} \quad \perp \lambda^{k}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.95)$$
$$0 \leq uDSM_{t,i} \quad \perp \lambda^{l}_{t,i} \geq 0 \quad \forall\, t,i \quad (A.96)$$
$$0 \leq \mathrm{MS}_i - is_i \quad \perp \lambda^{m}_{i} \geq 0 \quad \forall\, i \quad (A.97)$$
$$0 \leq \mathrm{MB}_i - ib_i \quad \perp \lambda^{n}_{i} \geq 0 \quad \forall\, i \quad (A.98)$$
$$0 \leq is_i \quad \perp \lambda^{o}_{i} \geq 0 \quad \forall\, i \quad (A.99)$$
$$0 \leq ib_i \quad \perp \lambda^{p}_{i} \geq 0 \quad \forall\, i \quad (A.100)$$

Eq. (A.85-A.100) are complementarity constraints. We linearize these constraints by replacing them with disjunctive constraints using the method described in Fortuny-Amat and McCarl (1981). Alternatively, a transformation using SOS1 variables as explained in Siddiqui and Gabriel (2013) or can be implemented as indicator constraints (GAMS, 2018). In the final formulation, we can also substitute $\lambda^{f}_{t,i}$, $\lambda^{g}_{t,i}$, $\lambda^{i}_{t,i}$, $\lambda^{j}_{t,i}$, $\lambda^{k}_{t,i}$, $\lambda^{l}_{t,i}$, λ^{o}_{i} and λ^{p}_{i} out.

<u>**Newly introduced sets, parameters and variables**</u>

<u>Parameters</u>

$\mathrm{M^a}, \mathrm{M^b}, \mathrm{M^c}, \mathrm{M^d}, \mathrm{M^e}, \mathrm{M^f}, \mathrm{M^g}, \mathrm{M^h}, \mathrm{M^i}, \mathrm{M^j}, \mathrm{M^k}, \mathrm{M^l}, \mathrm{M^m}, \mathrm{M^o}, \mathrm{M^p}$: Large scalars used to transform complementarity constraints (A.85-A.100) into disjunctive constraints [-]

<u>Variables</u>

$r^{a}_{t,i}, r^{b}_{t,i}, r^{c}_{t,i}, r^{d}_{t,i}, r^{e}_{t,i}, r^{f}_{t,i}, r^{g}_{t,i}, r^{h}_{t,i}, r^{i}_{t,i}, r^{j}_{t,i}, r^{k}_{t,i}, r^{l}_{t,i}, r^{m}_{i}, r^{n}_{i}, r^{o}_{i}, r^{p}_{i}$: Binary variables used to transform complementarity constraints (A.85-A.100) into disjunctive constraints [-]

$$qmax_i - qw_{t,i} - qi_{t,i} \leq \mathrm{M^a} * \left(1 - r^{a}_{t,i}\right) \quad \forall\, t,i \quad (A.101) \text{ and } \quad \lambda^{a}_{t,i} \leq \mathrm{M^a} * r^{a}_{t,i} \quad \forall\, t,i \ (A.102)$$
$$ib_i - soc_{t,i} \leq \mathrm{M^b} * \left(1 - r^{b}_{t,i}\right) \quad \forall\, t,i \quad (A.103) \text{ and } \quad \lambda^{b}_{t,i} \leq \mathrm{M^b} * r^{b}_{t,i} \quad \forall\, t,i \ (A.104)$$
$$ib_i * \mathrm{BDR} - qbout_{t,i} \leq \mathrm{M^c} * \left(1 - r^{c}_{t,i}\right) \quad \forall\, t,i \quad (A.105) \text{ and } \quad \lambda^{c}_{t,i} \leq \mathrm{M^c} * r^{c}_{t,i} \quad \forall\, t,i \ (A.106)$$
$$ib_i * \mathrm{BCR} - qbin_{t,i} \leq \mathrm{M^d} * \left(1 - r^{d}_{t,i}\right) \quad \forall\, t,i \quad (A.107) \text{ and } \quad \lambda^{d}_{t,i} \leq \mathrm{M^d} * r^{d}_{t,i} \quad \forall\, t,i \ (A.108)$$
$$\mathrm{PrDSM}_i * \mathrm{D}_{t,i} - dDSM_{t,i} \leq \mathrm{M^e} * \left(1 - r^{e}_{t,i}\right) \quad \forall\, t,i \quad (A.109) \text{ and } \quad \lambda^{e}_{t,i} \leq \mathrm{M^e} * r^{e}_{t,i} \quad \forall\, t,i \ (A.110)$$
$$qw_{t,i} \leq \mathrm{M^f} * \left(1 - r^{f}_{t,i}\right) \quad \forall\, t,i \quad (A.111) \text{ and}$$
$$\mathrm{WDT} * (\mathrm{EBP_t} + vnt + cpp_t) + \mu^{a}_{t,i} + \lambda^{a}_{t,i} \leq \mathrm{M^f} * r^{\mathrm{f}}_{t,i} \quad \forall\, t,i \ (A.112)$$
$$qi_{t,i} \leq \mathrm{M^g} * \left(1 - r^{g}_{t,i}\right) \quad \forall\, t,i \quad (A.113) \text{ and}$$
$$-\mathrm{WDT} * (\mathrm{ESP_t} + vnt * \mathrm{NM} + cpp_t) - \mu^{a}_{t,i} + \lambda^{a}_{t,i} \leq \mathrm{M^g} * r^{g}_{t,i} \quad \forall\, t,i \ (A.114)$$
$$soc_{t,i} \leq \mathrm{M^h} * \left(1 - r^{h}_{t,i}\right) \quad \forall\, t,i \quad (A.115) \text{ and } \quad \lambda^{h}_{t,i} \leq \mathrm{M^h} * r^{h}_{t,i} \quad \forall\, t,i \ (A.116)$$
$$qbout_{t,i} \leq \mathrm{M^i} * \left(1 - r^{i}_{t,i}\right) \quad \forall\, t,i \quad (A.117) \text{ and } \quad \mu^{a}_{t,i} + \frac{\mu^{b}_{t,i}}{\mathrm{EFD}} * \mathrm{DT} + \lambda^{c}_{t,i} \leq \mathrm{M^i} * r^{i}_{t,i} \quad \forall\, t,i \ (A.118)$$
$$qbin_{t,i} \leq \mathrm{M^j} * \left(1 - r^{j}_{t,i}\right) \quad \forall\, t,i \quad (A.119) \text{ and } \quad -\mu^{a}_{t,i} - \mu^{b}_{t,i} * \mathrm{EFC} * \mathrm{DT} + \lambda^{d}_{t,i} \leq \mathrm{M^j} * r^{j}_{t,i} \quad \forall\, t,i \ (A.120)$$
$$dDSM_{t,i} \leq \mathrm{M^k} * \left(1 - r^{k}_{t,i}\right) \quad \forall\, t,i \quad (A.121)$$
$$\text{and } \ \mathrm{CDSM_i} * \mathrm{WDT} + \mu^{a}_{t,i} - \mu^{d}_{t \in day,i} + \lambda^{e}_{t,i} \leq \mathrm{M^k} * r^{k}_{t,i} \quad \forall\, t,i \quad (A.122)$$

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$uDSM_{t,i} \leq \mathrm{M}^{\mathrm{l}} * \left(1 - r_{t,i}^{l}\right) \quad \forall\, t,i$ (A.123) and $-\mu_{t,i}^{a} + \mu_{t \in day,i}^{d} \leq \mathrm{M}^{\mathrm{l}} * r_{t,i}^{l} \quad \forall\, t,i$ (A.124)

$\mathrm{MS}_{i} - is_{i} \leq \mathrm{M}^{\mathrm{m}} * (1 - r_{i}^{m}) \quad \forall\, i$ (A.125) and $\lambda_{i}^{m} \leq \mathrm{M}^{\mathrm{m}} * r_{i}^{m} \quad \forall\, i$ (A.126)

$\mathrm{MB}_{\mathrm{i}} - ib_{i} \leq \mathrm{M}^{\mathrm{n}} * (1 - r_{i}^{n}) \quad \forall\, i$ (A.127) and $\lambda_{i}^{n} \leq \mathrm{M}^{\mathrm{n}} * r_{i}^{n} \quad \forall\, i$ (A.128)

$is_{i} \leq \mathrm{M}^{\mathrm{o}} * (1 - r_{i}^{o}) \quad \forall\, i$ (A.129) and $\mathrm{AICS} + \sum_{t} \mu_{t,i}^{a} * \mathrm{SY}_{t,i} + \lambda_{i}^{j} \leq \mathrm{M}^{\mathrm{o}} * r_{i}^{o} \quad \forall\, i$ (A.130)

$ib_{i} \leq \mathrm{M}^{\mathrm{p}} * \left(1 - r_{i}^{p}\right) \quad \forall\, i$ (A.131) and

$\mathrm{AICB} - \sum_{t} \lambda_{t,i}^{b} - \sum_{t} \lambda_{t,i}^{c} * \mathrm{BDR} - \sum_{t} \lambda_{t,i}^{d} * \mathrm{BCR} + \lambda_{i}^{k} \leq \mathrm{M}^{\mathrm{p}} * r_{i}^{p} \quad \forall\, i$ (A.132)

6.8.6 Final model formulation

The final model formulation is composed of Eq. (A.1-8) and (A.10). Eq. (A.9) can be transformed using discretization or the strong duality theorem. The lower level problem is incorporated in the MILP by Eq. (A.16-A.39), Eq. (71-73) and (A.101-A.132).

A.3.5 Including peak coincident network prices

These network charges can be quite easily integrated into the model. The grid cost recovery described by Eq. A.9 in this Appendix becomes Eq. 133 below where cpp_t stands for the (time-varying) network charge in €/kWh. fnt represents the uniform fixed network charge which might complement the time-varying network charge.

$$TotalGridcosts = \sum_{t=1}^{\mathrm{T}} \sum_{i=1}^{\mathrm{N}} \mathrm{PC}_{i} * cpp_{t} * (qw_{t,i} - qi_{t,i}) * \mathrm{WDT} + fnt \qquad (A.133)$$

cpp_t is a free variable. In the case of high solar PV penetration combined with low levels self-consumption, it might even be optimal to have negative network prices. The equation representing grid charges in the objective function of the lower level consumers (Eq. A.11 in this Appendix), becomes:

$$GridCharges_{i} = \sum_{t=1}^{\mathrm{T}} (qw_{t,i} - qi_{t,i}) * cpp_{t} * \mathrm{WDT} + fnt \qquad (A.134)$$

In this case, the regulator has to decide how to set the time-varying network charges in order to minimise the total system costs. Regarding the solution method, it is in this case extremely important that the bilinear products in the upper-level cost recovery constraint (Eq. 1) are efficiently linearized using the strong duality theorem instead of being discretised are for example done in Momber (2015, p. 102) and Schittekatte and Meeus (2018). The strong duality theorem says that if a problem is convex, the objective functions of the primal and dual problems have the same value at the optimum (Castillo et al., 2001). Another application of the strong duality theorem to linearize a bilinear term in an MPEC problem can be found for example in Ruiz and Conejo (2009).

The reason why the linearization using strong duality is helpful in this case is due to the fact that the time-varying network charges are by definition a function of the time-step while this is not the case for the previously modelled capacity based-charges, volumetric net-purchase and volumetric bi-directional charges. Therefore, when using the discretisation technique, the number of binaries needed to discretise the bilinear products with time-varying network charges are multiplied by the number of time-steps when compared to the number of binaries needed with non-time varying network charges. The introduction of such a high number of binaries slows down the model significantly and can even lead to not finding any solution while there is one.

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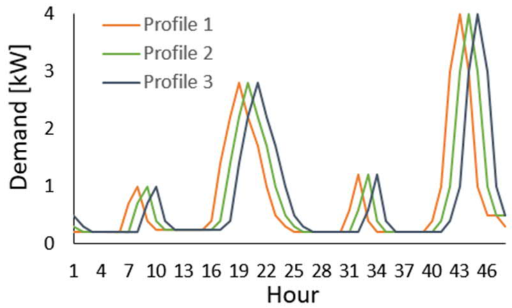
6.9 Appendix 6.B: sensitivity analysis

6.9.1 B.1 Data sensitivity analysis

To test the robustness of the results, an additional setup was evaluated. In the numerical example in the body of the text, only two consumer profiles are used. Each consumer type, active and passive, is represented by one profile, and the profiles are coincident. In reality, many individual profiles exist, and these will not be all coincident. In this appendix, three different consumer profiles were used. These profiles are shown in Figure B.1. together with the proportion of consumers per profiles and type.



	Active	Passive
Profile 1	16.7%	0 %
Profile 2	16.7%	50 %
Profile 3	16.7%	0 %

Figure B.1: Profiles and proportions consumers per profile and active/passive

6.9.2 B.2 Results sensitivity analysis

The results for the battery investment costs are shown in Table B.1. All grid costs are assumed to be driven by the aggregated peak demand. Please note that now the average capacity of the batteries installed by the different active consumer groups is shown. Logically, the capacities installed differ to a certain extent from the results in Table 15 but the observations remain the same.

When comparing the results in Figure 17 and Figure B.2, it can be seen that for expensive batteries, the performance in terms of the reduction of system costs is overestimated with coincident consumer profiles. If batteries are cheaper and thus more batteries are installed, the individual peaks will be flattened over multiple time-steps thus possibly also during the time steps other consumers have their peak demand and as a result the aggregated peak will decrease.

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Table B.1: Battery and solar PV investment per active consumer for the different network tariff designs under different investment cost assumptions for batteries and interaction with solar PV investments. All grid costs are assumed to be driven by the aggregated peak demand.

Distribution network tariff design		Benchmark – central planner	Capacity-based [€/kW]	Volumetric Net-purchase [€/kWh]	Volumetric Bi-directional [€/kWh]
Investment cost batteries		Average battery installed per active consumer [kWh] / PV in brackets [kWp]			
No PV installed, only batteries can be invested in by the active consumers	350 €/kWh	1.9 (0)	1.2 (0)	0.0 (0)	0.0 (0)
	300 €/kWh	1.9 (0)	1.2 (0)	0.0 (0)	0.0 (0)
	250 €/kWh	1.9 (0)	1.2 (0)	0.0 (0)	0.0 (0)
	200 €/kWh	6.2 (0)	3.9 (0)	0.0 (0)	0.0 (0)
	150 €/kWh	10.1 (0)	5.7 (0)	0.0 (0)	0.0 (0)
	100 €/kWh	12.1 (0)	6.9 (0)	0.0 (0)	0.0 (0)
Batteries and PV can be installed in by the active consumers	350 €/kWh	1.9 (0)	1.2 (0)	0 (4.9)	0.0 (0.6)
	300 €/kWh	1.9 (0)	1.2 (0)	0 (4.9)	0.0 (0.6)
	250 €/kWh	1.9 (0)	1.2 (0)	0 (4.9)	0.0 (0.6)
	200 €/kWh	6.2 (0)	3.9 (0)	0 (4.9)	0.0 (0.6)
	150 €/kWh	10.1 (0)	5.7 (0)	0 (4.9)	0.5 (0.6)
	100 €/kWh	12.1 (0)	7.3 (0.7)	3.6 (5)	1.7 (1.1)
Active consumer has a 5 kWp solar PV, batteries can be invested in	350 €/kWh	1.8 (5)	1.0 (5)	0.0 (5)	0.0 (5)
	300 €/kWh	2.1 (5)	1.4 (5)	0.0 (5)	0.0 (5)
	250 €/kWh	2.1 (5)	1.4 (5)	0.0 (5)	0.0 (5)
	200 €/kWh	6.2 (5)	1.8 (5)	0.0 (5)	5.2 (5)
	150 €/kWh	11.0 (5)	6.2 (5)	0.0 (5)	5.2 (5)
	100 €/kWh	12.4 (5)	7.4 (5)	3.6 (5)	11.7 (5)

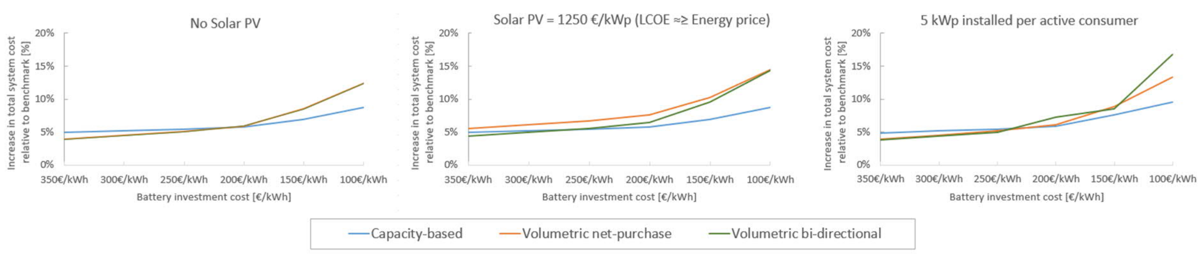

Figure B.2: Increase in total system costs for the three network tariff structures when compared with a central planner. Sensitivity for three different assumptions regarding solar PV adoption and the investment cost of storage.

Table B.2 shows the result for the battery adoption under different TOU energy prices. Again, the capacities installed differ to a certain extent from the results in Table 16 but the observations remain the same.

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Table B.2: Battery and solar PV investment per active consumer for the different network tariff designs under different investment cost assumptions for batteries and interaction with solar PV investments. All grid costs are assumed to be driven by the aggregated peak demand.

Distribution network tariff design		Benchmark – central planner		Capacity-based [€/kW]		Volumetric Net-purchase [€/kWh]		Volumetric Bi-directional [€/kWh]	
Energy price		TOU1	TOU2	TOU1	TOU2	TOU1	TOU2	TOU1	TOU2
Investment cost batteries		Battery installed per active consumer [kWh] / PV in brackets [kWp]							
No PV installed, only batteries can be invested in by the active consumers	350 €/kWh	1.9 (0)	8.6 (0)	1.2 (0)	3.7 (0)	0 (0)	0 (0)	0 (0)	0 (0)
	300 €/kWh	1.9 (0)	12.1 (0)	1.2 (0)	6.1 (0)	0 (0)	0 (0)	0 (0)	0 (0)
	250 €/kWh	3.5 (0)	12.7 (0)	2.1 (0)	7.0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
	200 €/kWh	10.0 (0)	13.2 (0)	5.3 (0)	7.5 (0)	0 (0)	0 (0)	0 (0)	0 (0)
	150 €/kWh	12.1 (0)	15.0 (0)	6.6 (0)	8.1 (0)	0 (0)	0 (0)	0 (0)	0 (0)
	100 €/kWh	12.7 (0)	16.3 (0)	7.2 (0)	8.3 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Batteries and PV can be installed in by the active consumers	350 €/kWh	1.9 (0.4)	8.6 (0)	1.2 (0.4)	3.7 (0)	0 (5)	0 (0.7)	0 (0.7)	0 (0.4)
	300 €/kWh	1.9 (0)	12.1 (0)	1.3 (1.4)	6.1 (0)	0 (5)	0 (0.7)	0 (0.7)	0 (0.4)
	250 €/kWh	3.5 (0)	12.7 (0)	1.9 (1.3)	7.0 (0)	0 (5)	0 (0.7)	0 (0.7)	0 (0.4)
	200 €/kWh	10.0 (0)	13.2 (0)	5.2 (0.8)	7.5 (0)	0 (5)	0.1 (0.9)	0 (0.7)	0.1 (0.5)
	150 €/kWh	12.1 (0)	15.0 (0)	6.6 (0.7)	8.1 (0)	0 (5)	1.9 (1.5)	1.0 (0.9)	2.8 (1.4)
	100 €/kWh	12.7 (0.4)	16.3 (0)	7.3 (0.6)	8.3 (0)	4.5 (5)	8.2 (3.1)	6.8 (2.8)	8.2 (3.2)
Active consumer has a 5 kWp solar PV, batteries can be invested in	350 €/kWh	2.1 (5)	8.5 (5)	1.3 (5)	2.6 (5)	0 (5)	0 (5)	0 (5)	5.2 (5)
	300 €/kWh	2.1 (5)	12.4 (5)	1.4 (5)	5.3 (5)	0 (5)	0 (5)	0 (5)	5.2 (5)
	250 €/kWh	4.1 (5)	12.4 (5)	1.5 (5)	6.3 (5)	0 (5)	3.7 (5)	4.8 (5)	5.2 (5)
	200 €/kWh	9.6 (5)	13.0 (5)	4.3 (5)	8.1 (5)	0 (5)	5.2 (5)	5.2 (5)	7.5 (5)
	150 €/kWh	12.4 (5)	14.9 (5)	6.0 (5)	9.2 (5)	0 (5)	5.2 (5)	5.2 (5)	7.6 (5)
	100 €/kWh	12.4 (5)	18.2 (5)	6.7 (5)	10.3 (5)	4.5 (5)	7.6 (5)	7.6 (5)	11.7 (5)

Table B.3 shows the relative difference in system costs between flat energy prices and TOU energy prices for different distribution network tariff designs and investment cost of batteries.

Table B.3: Relative difference in system costs between flat energy prices and TOU energy prices for different distribution network tariff designs and investment cost of batteries.

Distribution network tariff design		Benchmark – central planner		Capacity-based [€/kW]		Volumetric Net-purchase [€/kWh]		Volumetric Bi-directional [€/kWh]	
Energy price		TOU1	TOU2	TOU1	TOU2	TOU1	TOU2	TOU1	TOU2
Investment cost batteries		Difference in total system costs compared to a flat energy price [%]							
No PV installed, only batteries can be invested in by the	350 €/kWh	-0.4%	-1.9%	-0.3%	-1.1%	0.0%	0.0%	0.0%	0.0%
	300 €/kWh	-0.4%	-4.4%	-0.3%	-2.2%	0.0%	0.0%	0.0%	0.0%
	250 €/kWh	-0.5%	-7.5%	-0.3%	-3.7%	0.0%	0.0%	0.0%	0.0%
	200 €/kWh	-2.0%	-10.7%	-1.0%	-5.3%	0.0%	0.0%	0.0%	0.0%
	150 €/kWh	-3.1%	-12.6%	-1.4%	-6.3%	0.0%	0.0%	0.0%	0.0%

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active consumers	100 €/kWh	-3.6%	-14.5%	-1.6%	-6.9%	0.0%	0.0%	0.0%	0.0%
Batteries and PV can be installed in by the active consumers	350 €/kWh	-0.4%	-1.9%	-0.3%	-1.1%	-1.0%	-0.5%	-0.1%	0.0%
	300 €/kWh	-0.4%	-4.4%	-0.3%	-2.2%	-1.0%	-0.5%	-0.1%	0.0%
	250 €/kWh	-0.5%	-7.5%	-0.4%	-3.7%	-1.0%	-0.5%	-0.1%	0.0%
	200 €/kWh	-2.0%	-10.7%	-1.1%	-5.3%	-1.0%	-0.2%	-0.1%	0.5%
	150 €/kWh	-3.1%	-12.6%	-1.5%	-6.3%	-1.0%	1.2%	0.4%	1.8%
	100 €/kWh	-3.6%	-14.5%	-1.6%	-6.9%	-2.7%	0.1%	2.9%	0.2%
Active consumer has a 5 kWp solar PV, batteries can be invested in	350 €/kWh	-0.9%	-0.8%	-0.8%	0.0%	-0.4%	1.2%	-0.1%	3.1%
	300 €/kWh	-0.9%	-3.1%	-0.8%	-0.9%	-0.4%	1.2%	-0.1%	1.7%
	250 €/kWh	-1.0%	-6.1%	-0.8%	-2.2%	-0.4%	1.4%	1.7%	0.3%
	200 €/kWh	-2.4%	-9.0%	-1.2%	-3.8%	-0.4%	-2.1%	-0.7%	-5.2%
	150 €/kWh	-3.3%	-10.8%	-1.6%	-5.1%	-0.4%	-3.5%	-0.7%	-5.9%
	100 €/kWh	-3.4%	-12.9%	-1.4%	-6.0%	-2.1%	-8.4%	-3.5%	-2.0%

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7 Annex 7: The demand response baseline impact on storage business models and regulation[48]

Ariana Ramos[a],
[a] Vlerick School of Business, Avenue du Boulevard 21, 1210 Brussels,

Keywords: demand response, prosumers, baseline, electricity markets.

Abstract

The baseline in demand response refers to the load that users would have consumed in the absence of a demand response program. Consumers sell flexibility in electricity markets, meaning a modification of their consumption patterns based on external signals. The baseline is important because payments for demand response are directly based on the difference between the baseline and actual metered demand. The difficulty lies in the difficulty in accurately measuring the service provided for remuneration. Data may not be readily available to calculate the baseline appropriately or seasonal and situational variations have to be taken into account. This paper examines both the theory and the practices regarding baseline calculation. The theory has evolved significantly throughout the past 10 years, complex statistical based models are explored. Practices in selected countries are compared to the theory. It is found that the practices regarding baseline setting in Europe have not caught up to the academic theory due to difficulties in measurement and real-time implementation.

7.1 Introduction

The value of demand response services is derived from a comparison between the situation before demand response and the situation after an event. Therefore, the baseline is an indication of 'what would have happened', it is an estimation that can lead to controversy. The main baseline approaches found in literature are compared with current baseline practices in selected European countries. First, literature is classified into three main categories: regression approach with adjustments, last X of Y, and meter-before/meter-after DR. Second, the main practices found across selected countries in Europe are presented and compared to the methods found in literature. Third, the current regulatory framework set by the CEP and the Network Codes is discussed. Finally a conclusion is presented highlighting the need for more specific regulation regarding baseline calculation methodologies.

[48] Paper presented at the European Energy Markets Conference in Slovenia 2019. Available at: https://ieeexplore.ieee.org/abstract/document/8916212

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7.2 The baseline in theory

The demand response baseline is directly linked to the performance measurement and remuneration of demand response. Demand response capacity is defined as ‘a consumer’s right to sell unused energy, relative to an established customer baseline, into wholesale energy markets;’ (H. Chao, 2011). Another view defines the demand response baseline as a ‘a counter-factual load that could have been consumed in the absence of the DR program’ (Jazaeri et al., 2016). The difficulty of establishing a baseline is identified as a barrier for demand response in smart-grids (Weck, van Hooff, & van Sark, 2017).

The literature with respect to baseline calculation is grouped into three main categories as illustrated in Figure 22. The categories are grouped according to the time before the demand response event upon which they are calculated. A regression approach with adjustments is calculated based on a longer timeframe, ranging from months up to a year. A last X of Y approach takes the last few days of a month or week. While a meter-before/meter-after method takes the last few hours or even minutes before and after a demand response event in order to draw the baseline. Each method and corresponding literature is presented below:

1. Statistical approach with adjustments: In a regression model historical data is used to calculate the coefficients of a linear model. The model can be adjusted to represent weather or load data immediately prior to the demand response event. This is done to take into account specific weather conditions that may lead to a need for demand response in the system. Average and regression based methods are compared in (Coughlin, Piette, Goldman, & Kiliccote, 2009), (Coughlin, Piette, Goldman, Kiliccote, & Lawrence, 2008). It is found that including temperature and adjustment variables improves results, but more elaborate models do not show better performance in terms of accuracy. Uncertainty is introduced into a regression model to test parameter error in (Mathieu, Callaway, & Kiliccote, 2011). Two types of baselines based on statistical data are identified in (EnerNOC, 2011). Baseline type I is based on meter data, weather and load conditions, while baseline type II is a statistical sampling to generate a baseline of portfolio customers where interval meter data is not available. Non-linear regression models to estimate an hourly baseline are used in (Jazaeri et al., 2016). Past consumption averages are correlated to weather conditions in (H. P. Chao, 2010; S3C Project., 2013). It is found that the choice of baseline affects stakeholder profits and the expected amount of demand response in (Wijaya, Vasirani, & Aberer, 2014).

2. X of Y approaches: either the highest days or an average of X days in a period of Y days is used to calculate a baseline (Jazaeri et al., 2016). The methodologies are called ‘high X of Y’ or ‘Last Y days’ accordingly. Variations of the X of Y approach have been proposed and compared in (Coughlin et al., 2009; EnerNOC, 2011; Wijaya et al., 2014).

3. Meter before/Meter after DR: this methodology uses the load immediately before and immediately after the event to calculate the amount of demand response dispatched

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(Goldberg & Kennedy, 2013) (Holmberg, Hardin, & Koch, 2013). Polynomial interpolation is discussed as a way to fit a polynomial function to the load using the aforementioned data (Jazaeri et al., 2016). This method is mainly intended in the literature for short term demand reductions.

Most of the literature aims to perform numerical analyses of the performance of the different methods. There is a wider amount of literature available on the more numerically oriented methods such as different types of regressions, and averaging methods. Less academic literature exists regarding the meter before/meter after DR method. Nevertheless, as we shall see in the following section, this method is being implemented by system operators to measure demand response. It is perhaps less academically interesting than the other methods but due to its simplicity it is more straight forward to implement. It has drawbacks, though, since a demand response supplier could artificially create peaks in its consumption in order to demonstrate a higher demand response potential.

7.3 The baseline in practice

The current practices of selected countries are organized according to the baseline methodologies exemplified in Figure 22: statistical approach with adjustments, X of Y approaches, and meter before/ meter after approaches.

7.3.1 Statistical approach with adjustments

The statistical approach with adjustments consists mainly of regression methods adjusted for current conditions such as weather and renewable energy availability. Meter data or statistical sampling is used to create a baseline upon which to measure demand response. The main practices regarding a statistical approach for France and Belgium are described next.

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Figure 22: Baseline Methods in Selected Countries

France. A regression approach is used in France as one of the methods to establish a baseline. This method applies only to remotely measured sites. Consumption forecasts are provided by the aggregator. The historical load data is equal to the load curve of each site. The half hourly load data of a site is the average value over each of the three 10 minute periods constituting the half hour, of the average consumption of the 10 minute period over either the last 10 days, or the last 4 weeks depending on the certification modality chosen. A method using the median of each 10 minute period over the last 10 days is also possible. In order to verify the load reductions an error measurement is carried out, with respect to the actual load curve and the estimated baseline. The error, meaning the deviation between the committed demand reduction and the actual demand reduction should be less than 40% (Rèseau de Transport d'électricité, 2018).

Belgium. In Belgium a product called strategic reserve is established to cover structural system shortages. Demand can participate through the 'strategic reserve delivered by a reduction in the offtake on the demand side (SDR)'. There are two main modes of delivery upon request of the system operator, either reduce demand by a certain amount, or reduce demand to a fixed offtake. The service is remunerated both for availability and for activation (Elia System Operator, 2018c). To calculate the baseline a maximum reference power is determined based on validated data for the las three winter periods and an estimated flexible volume per delivery point. The supplier of SDR must calculate an hourly available power based on the flexibility volume available per delivery point. The SDR supplier must determine an availability rate during predefined periods with a required threshold tied to the probability of activation during the available periods. The results should comply with the certification criteria set by the system operator (Elia System Operator, 2017a, 2017c).

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7.3.2 Last X of Y

In a last X of Y approach a baseline is calculated taking measurements of the highest or average X days, hours, or minutes in a period of Y days, hours or minutes. The current practices of this method in France, Switzerland, and Poland are outlined next.

France. Historical consumption data is used for load reduction entities that contain more than 3000 sites. For each 10 minute period of the load reduction period the reference load curve is equal to the sum of each reference curve for profiled load sites. The value of each reference curve is equal to the initial reference power for that site. The initial reference power is the average of the load consumption curve of the site over the last two 10 minute periods preceding the start of the individual demand reduction (Rèseau de Transport d'électricité, 2018).

Switzerland. In 2013 Switzerland implemented measures to open up to demand response by allowing Balancing Service Providers to aggregate groups of load to provide ancillary services: including FCR, FRRa, and FRRm (Swissgrid Ltd., 2018b). Currently demand response does not participate in the wholesale market but it is under consideration according to a consultation document issued by Swissgrid (Swissgrid Ltd., 2015). Since 2013 different producers and consumers of energy can be grouped in a 'virtual power plant' to propose system services together (Swissgrid Ltd., 2018a).
In Switzerland the baseline is defined 'as the measured value of the load before being influenced by the aggregator' (SEDC, 2017). All balancing service providers must go through a similar prequalification procedure to offer balancing services to the TSO, including demand response providers, the service measurement is defined in this stage.

Poland: According to the preliminary project, there will be 5 baseline methodologies, the most appropriate will be applied automatically, which may be very challenging for proper demand reduction volume forecasting. The historical approach in Poland has been "X of Y", whereby recent similar days are used.

7.3.3 Meter before/meter after:

The meter before/ meter after methods consists of comparing the meter readings of a demand response provider before and after a demand response event is called. Selected applications of this method in France, Belgium, Ireland and the Netherlands are described next.
France. Consumption before and after a demand reduction event is measured through a method called the 'double reference adjusted rectangle'. This is the default method used for setting the baseline. If a demand reduction provider wishes to use another method they need to make a special request to RTE. The half hourly reference load curve of the demand response entity is equal to the minimum value between the initial reference power and the final reference power for a demand reduction, and the maximum value between the initial reference power and the final reference power for a demand increase. The initial reference power is the half-hourly average of the load curve of the demand response entity, calculated over the minimum between the duration of the demand response event and two hours. The final reference power is the half-hourly average of the load curve of the demand response entity, calculated over a duration equal to the demand response

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event and two hours, starting right after the end of the event (Rèseau de Transport d'électricité, 2018).

Belgium. In Belgium there are different baseline requirements depending on the demand response product activated. For the 'non-CIPU mFRR' product, the baseline is established based on the quarter hour meter reading preceding the demand response event.
A paid offtake interruptibility contract is available for large consumers connected to the transmission grid in Belgium, called the ICH product. This product is part of the mFRR reserves contracted by Elia. When needed, Elia automatically reduces a consumer's load within three minutes, there is no prior notice to the event. In the ICH product the power reserve is the difference, if positive, between the reference power of the industrial unit subject to interruptibility and the shedding limit stipulated in the contract. The assessment of the volume of interrupted energy is done quarter-hourly, based on the difference between the nomination and the actual power taken from the grid given by the meter reading. The nomination refers to the submitted off-take schedule done by the balancing responsible party for that connection one day in advance of operation (Elia System Operator, 2017b).
Demand response participating in R1 is evaluated a-posteriori by frequency-variation reports drawn up by the TSO to verify the proper activation of the programme as well as to analyse the process (SEDC, 2017).

Ireland. Demand response is allowed to participate as Demand Side Units (DSU) eligible for capacity payments in the Single Electricity Market (Joint Research Centre, 2016). A DSU consists of one or more individual demand sites that can be dispatched by the TSO as if it were a generator (Eirgrid Group, 2018a). More recently demand response can also offer DS3 system services to the TSO. The baseline is established using a meter-before/meter-after system (SEDC, 2017). For demand response verification DSUs have to submit the following day's projected aggregate demand of all the sites comprising the DSU in half-hour intervals (Eirgrid Group, 2018b). This data is used as a baseline. It is then compared to actual meter readings and it must be accurate to within 5%.
The Netherlands. Baseline settlement depends on the contractual relationship between the end consumer, their BRP and their retailer. The BSP is required to supply measurements to the TSO for FRRm. Continuous data is required for FRRa on 4 second intervals. Values are measured 1 hour prior to activation and 1 hour after activation on minute intervals for emergency power (SEDC, 2017). For mFRR the reference is the average consumption/production during the 5 minute period preceding the activation signal. The delivered energy is the difference between the measured consumption and this reference.

7.4 The baseline in the Clean Energy Package and network codes

Demand response is enabled in the current regulatory proposals and existing network codes. This section explores the provisions for a baseline made in the proposal for a directive on common rules for the internal market for electricity (the directive), the proposal for a regulation on common rules for the internal market for electricity (the regulation), the network code on a system operation guideline, the demand connection code and the network code on balancing.

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Demand response is enabled in the directive proposal, first through the legal figure of active consumers in article 15, and they are directly enabled to offer demand response in article 17 'Demand Response'. In article 15(1) active consumers are entitled to 'generate, store, consume and sell self-generated electricity in all organized markets either individually or through aggregators without being subject to disproportionately burdensome procedures and charges that are not cost reflective'. In 15(2) consumers are 'subject to cost reflective, transparent and non-discriminatory network charges, accounting separately for the electricity fed into the grid and the electricity consumed from the grid'. Article 17(3b) dictates member states to ensure that their regulatory framework encourages the participation of aggregators in the retail market and that transparent rules clearly assigning roles and responsibilities as well as rules for data exchange are clearly set. The same article, 17(5) specifies that member states shall define technical modalities for the participation of demand response in their markets. The baseline is not directly mentioned in the directive as such, but provisions for metering technology and data management, that would enable a baseline establishment are set. Article 19(1) encourages member states to optimise the use of electricity by providing energy management services, innovative pricing formulas and smart metering systems or smart grids (European Commission, 2016c). Article 20(a) sets out the principles for the smart meter roll-out, the metering systems should 'accurately measure actual electricity consumption and provide to final customers information on actual time of use.' The information provided to consumers should be easily available to final customers at no additional cost to support automated demand response and other services. Other provisions on data security and rights to a smart meter are set in articles 20, 21 and 23. Aggregators can be eligible to access data of final consumers, with their explicit consent according to article 23(1).

In the regulation proposal market participation of consumers shall be enabled by aggregation of load from multiple demand facilities to provide joint offers on the electricity market, article 3(1d). Article 11 states that 'dispatching of power generation facilities and demand response shall be non-discriminatory and market based', with some exceptions for small renewable or cogeneration installations, and demonstration projects. In article 55(1n) the regulation calls for the establishment of a network code on demand response, including aggregation, energy storage, and demand curtailment rules.

The system operation guideline establishes minimum data that must be exchanged between the TSO, the DSO, and demand facilities participating in demand response, connected at transmission and distribution levels in articles 52 and 53 respectively (European Commission, 2017a). The articles refer to data about maximum and minimum power available from demand response, availability forecasts, real-time active and reactive power capabilities, and confirmation that the estimates of the actual values of demand response are applied. Specific methods of evaluating the demand response provided, baseline establishment, are not mentioned.

The demand connection code outlines definitions of demand response, active and reactive power control, demand response transmission constraint management, demand aggregation, demand response system frequency control and demand response very fast active power control (European Commission, 2016b). In articles 27 and 28 the code also outlines that demand response may bring active and reactive power control, or demand response transmission constraint management to

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system operators, and it can be either remotely controlled or autonomously controlled. Demand response services can include upward or downward modification of demand. Frequency and voltage requirements for demand response services are also established along with other general technical specifications. Specific requirements related to data transfer and verification of the demand response event are to be set by the relevant system operator and specified in a contract with the demand facility owner or aggregator.

The provisions set within the network code on balancing for balancing service providers would apply to aggregators if they participate in the balancing markets (ENTSO-E, 2014). These provisions relate to information transfer about service and availability schedules, energy bids, and service capacity (Article 16). Article 3(1f) states that the code aims to facilitate the participation of demand response including aggregation facilities and energy storage while ensuring that they compete with other balancing services at a level playing field. The code enables the TSOs of each member state to develop a proposal regarding the terms and conditions for balancing service providers and for balance responsible parties, including the terms and conditions for the aggregation of demand and storage facilities (Article 18(5c)). The baseline as such is not specifically defined in the network code on balancing.

Overall while demand response is enabled by the current regulation the specifics of its operation, including the establishment of the baseline, are not yet regulated at a European level. At the current moment Member states and even system operators have the liberty to set terms and conditions as they see fit for current demand response services being contracted. The proposal for a regulation on common rules on the internal market for electricity does call for a network code on demand response. In the coming years the rules will be set, based on the current regulatory discussions.

7.5 Conclusions

The baseline is relevant because it defines the amount of MW and MWh being sold as a product for availability and energy. The baseline is required to estimate the service delivered, since demand response is defined as a variation in the expected load profile. The remuneration to which the demand service provider is entitled depends entirely on the establishment of the baseline. There are several different methods proposed to establish the baseline that can be grouped in three categories: statistical approach with adjustments, last X of Y, meter before/ meter after. The variety of methods proposed has policy implications given the amount of demand response calculated may vary depending on the method used. Policy that clearly outlines principles to build a baseline would serve to clearly define the demand response product. In turn this would homogenize the expected profit gained by demand response providers.

In conclusion, demand response is an emerging market that has yet to develop to its full potential. As stated in the introduction only about 20% of the demand response capacity potential is being traded today. It is clear that European policy makers want to empower consumers through the Clean Energy package proposal. The coming years will see the development of clear rules enabling the participation of demand response to the benefit of society. Final consumers, who up to now have been passive price-takers, can finally set foot in the electricity market. Only when consumers

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can be aware of and adequately respond to market conditions can we say that they are facing a level playing field.

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8 Annex 8: Policy Brief on Recommendations

8.1 Executive Summary

The recommendations presented in this document address real-life issues encountered by the project developers who led the technology demonstrations of the STORY project. Each of the demo leaders faced unique challenges in bringing technology to market, and in bringing systems from different providers together. It became clear during the project that the market for storage is in its infancy in all aspects of the value chain, from the technology supply, to troubleshooting installed equipment, connecting and operating the technology, and participating in markets. It is the hope of the STORY project consortium that these recommendations will pave the way to enable an economically feasible growth of the storage market.

A first description of main regulatory topics was presented by Vlerick in a webinar in May 2019[49]. The main regulatory discussions were debated internally with demo leaders and STORY project participants during two General Meetings in April 2019 and in October 2019. An iterative process with the project participants was then carried out to identify the main issues affecting the STORY project demos. The issues identified were then narrowed down and discussed during a one-day meeting in Leuven Belgium in January 2020 followed by e-mail feedback rounds. The STORY project has identified five main areas of discussion regarding business models and regulation for storage:

- Legal definition of storage,
- Network tariffs,
- DSO participation in storage projects,
- Market design
- Business model enablers.

Section 3 presents a discussion and recommendations on the legal definition of storage. During the project it became apparent that it is unclear whether storage is treated as generation or as load in the grid guidelines of each country. This led to difficulties in assessing connection requirements, servicing by the DSO, as well as taxes and tariffs applicable. In light of these issues, three main recommendations are put forward: 1/ there should be a clear distinction in regulation between storage assets set behind the meter and storage assets directly connected to the network, 2/Heat and gas storage should also be contemplated in the regulation and grid codes, 3/ Regulation should make a distinction between permanent versus mobile storage units.

Section 4 presents recommendations on network tariff design. Network tariffs represent a significant portion of the energy fees that a market participant pays, thus directly affecting the business case for storage. This section presents the results of a study done during this project on tariff design trade offs. A central planner scenario is compared to capacity based tariffs, volumetric net-metered tariffs and volumetric bi-directional tariffs. The results show that volumetric net-metered tariffs de-incentivize investment in storage units as users then use the network as a battery; while volumetric bi-directional tariffs provide an incentive to over invest in batteries.

[49] A recording of the webinar is available here: http://horizon2020-story.eu/webinar-on-regulation-for-storage/

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Capacity based tariffs prove to be the most efficient design for society, taking into account network costs recovery as well as the individual business case for storage. The STORY project recommends that tariff design should aim for grid cost recovery, technology neutrality in tariff design, and a distinction should be made between energy destined for storage versus energy destined for final consumption.

Section 5 discusses the extend of DSO participation in storage projects. It was seen during the demos of the STORY project that integrating larger scale batteries into a distribution network can cause disturbances in the network. Active participation by the DSO was necessary to enable the safe and reliable operation of the battery systems. The main role of a DSO should be to act as a grid facilitator enabling market actors to perform their commercial activities. Therefore, on principle, and in line with European regulation, DSOs should not own storage assets. Nevertheless, every DSO needs to learn how to connect and manage storage in their network before they can efficiently facilitate the process. In the experience of the STORY project, the learning curve is quite steep and requires adaptations to the SCADA management systems of the DSO. Therefore, it is the proposal of the STORY project that allowing DSOs to exceptionally operate a storage system as part of their network assets could serve two purposes: 1/ Enabling the adaptation of the DSO's systems to accommodate and service storage facilities, 2/ Enabling DSOs to observe the impact of storage in their network in order to draft product definitions for services that should be later provided by commercial actors.

Section 6 discusses electricity market design considerations that affect the business case of storage. Two aspects of market design are discussed: the first is the design of balancing markets to allow the participation of flexibility coming from different types of technologies, and the second is access to markets for small consumers through aggregation. It was the experience of the STORY project demos, that the value created by the technology installed, was not directly monetizable. Market design requirements, and minimum volume criteria pose challenges for the participation of smaller scale storage in distribution. It became clear that aggregation of resources is necessary to reap the value of flexibility as a whole. Storage is a technology that can provide flexibility and should be considered in a portfolio of flexibility options. The STORY project proposes two main recommendations for market design: technology neutrality in service design and assurance that consumers are enabled to valorise flexibility.

Section 7 discusses business model recommendations for storage. An iterative process with the STORY partners and demo leaders lead to a classification of the storage business models based on two main criteria: 1/ the level of resource aggregation, 2/ the different revenue streams as value is created for different market parties such as the owner of storage, services for the DSO and TSO, and market arbitrage. It became clear that the business model for storage depends on being able to stack revenue streams coming from different markets. Reaping the value of storage from residential consumers is dependent on retailer and aggregation innovation. Finally, the markets to valorize storage are not well defined yet, especially at the distribution level, it is necessary that DSOs draft clear product definitions that would enable a business case for smaller local flexibility providers.

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8.2 Introduction

The five topics mentioned above are presented in this document: legal definition of storage, network tariffs, DSO participation in storage projects, market design, and business model enablers.

In addition to the unified views of the STORY consortium, the views of specific partners are presented in Boxes. Each of these boxes represents the opinions of the partner who authored them, and may differ from the main recommendations in this document. It was decided to include these boxes as policy discussions should take the views of different stakeholder into account.

In order to present the recommendations, the background and relevance of each topic is discussed first, and then, the STORY project recommendation is presented. Each section is supported by work done in the STORY project, which can be found in Deliverable 8.5: Energy Storage in Distribution – Deployment Handbook; the relevant chapters are quoted in each section.

The authors of this document would like to thank the STORY partners who have been directly involved in the recommendations drafting process through phone meetings, email iterations and a one day workshop in Belgium in January 2020 are: VTT, UL, PI, JR, CEN, THNK, FLEX, EXL, BEN and VITO. Similarly, we would also like to thank other partners have been involved in the supporting studies to the recommendations through participation in business model workshops, and input during the STORY project general meetings: BASN, ABB, B9 and UCL.

8.3 Legal Definition of Storage

In order to discuss the issues encountered and the proposed recommendation regarding the legal definition of storage, first background information and exmples in regulation are presented, and second the STORY project recommendation is explained.

8.3.1 Background

The legal definition of storage affects whether an asset is considered as a consumption or generation unit connected to the network. This point is recognized in the Commission staff working document 2017-61 which states that: "The lack of a clear definition for energy storage in the regulatory framework resulted in a lack of coherence in the classification of storage facilities into generation and/or consumption across Member States" (European Comission, 2017).

To facilitate the discussion on the effect on this lack of clarity and how this could be addressed, this section presents the legal definition in the clean energy package first. Then, the definition and practical use of storage as a service provider in Belgium and Spain are outlined.

According to the Directive on common rules for the internal market, in the EU clean energy package, energy storage means, in the electricity system, deferring the final use of electricity to a later moment than when it was generated or the conversion of electrical energy into a form of energy which can be stored, the storing of that energy, and the subsequent reconversion of that energy back into electrical energy or use as another energy carrier (European Parliament and the Council of the EU, 2019). More

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broadly, storage can be thought of as moving energy over time (Rastler & Electric Power Research Institute, 2010).

In Belgium, storage is defined at the DSO level as ‘a unit capable of receiving, storing and feeding back electrical energy connected to a distribution network, regardless of the nature of the technology in use’ (Synergrid, 2019).[50] In the Energiebesluit a stationary installation for electrochemical electricity storage is defined as: ‘a fixed installation consisting of one or more electrochemical cells with which electrical energy is taken from the network or the internal installation to which it is connected, to transfer that electrical energy at a later time back to the network or the indoor installation to which it is connected’[51] (Vlaamse Regering, 210AD). In terms of service provision by storage assets, Elia, the Belgian TSO considers storage as a ‘limited energy content’; which are units that cannot unlimitedly provide a certain capacity for ancillary services and the capacity remuneration mechanism (Elia System Operator, 2019). Service provision from these assets follows a specific set of rules, for example, FCR providing units with a limited energy reservoir should be able to be fully activated for at least 30 minutes at any given moment during their delivery. The service provider also needs to present toward the TSO their energy management strategy, which needs to be approved.

In Spain they have introduced a different approach as they include the use of storage as part of a self-consumption installation. In Spain, storage is not considered within primary legislation, rather it is considered as a part of self-consumption activities of consumers and legislated in a self-consumption decree (Ministerio para la Transición Ecológica, 2019). Self-consumption is defined as ‘consumption by one or several consumers of electrical energy coming from generation installations next to the consumption installation and associated with them’. There are two main modalities of self-consumption: with and without excess of energy (that will be poured into the grid). Self-consumption without excess can’t pour energy into the grid while self-consumption with excess can pour energy into the distribution or transmission network

8.3.2 STORY Recommendation

The legal definition of storage that can be found in legislation so far, defines the role of storage in the system, broadly speaking, as a system to defer the use of energy over time. However, it fails to define whether to consider storage as generation or as consumption. This has implications on the tariffs for use of the network, the levies and fees, and the obligations of the storage asset management.

The STORY project advocates for the harmonization of the legal definitions of storage used by the TSO, DSO, market design platforms and participating actors. The energy package proposes a legal

[50] ‘Een eenheid die in staat is om elektrische energie uit het netwerk van een DNG of het distributienet op te nemen, op te slaan en terug te voeden, onafhankelijk van de aard van de technische uitvoering van die eenheid.’ Technish Voorschrift C10/11

[51] ‘In dit artikel wordt verstaan onder stationaire installatie voor elektrochemische opslag van elektriciteit: een vast opgestelde installatie die bestaat uit een of meer elektrochemische cellen waarmee elektrische energie wordt afgenomen van het netwerk of de binneninstallatie waaraan ze gekoppeld is, om die elektrische energie op een later moment terug te voeden aan het netwerk of de binneninstallatie waaraan ze gekoppeld is.’

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definition of the act of storing energy which can constitute a first step in this direction. However, we consider it could be extended by:

- Distinguishing between storage assets set behind the meter and storage assets directly connected to transmission or distribution assets as otherwise, directly connected assets run the risk of incurring grid double charges as will be discussed below.
- Including heat and gas storage, as well as their interaction with the electricity network as currently only electrical storage is considered in the regulation.
- Distinguishing in the grid connection codes between permanent versus mobile storage units.

8.4 Network Tariffs

The background subsection gives an overview of how tariff design affects the business case for residential storage and what are the current practices in the countries participating in the STORY project. This is followed by the recommendations for improvement from STORY project.

8.4.1 Background

Network tariffs have been studied in the context of WP8 and presented in 'D8.2 Intermediate Reporting for STORY, Advisory Board and Projects Council.' In addition, current practices regarding tariff design are also presented. This section presents the interaction between distribution tariff design and the business case for residential storage as well as the current developments in STORY participating countries.

8.4.2 Distribution tariff design and the business case for residential storage[52]

Storage installations can be used for two main purposes, one is to achieve savings on the electricity bill when coupled with self-generation and the other is to offer services to electricity stakeholders.

In both cases the network charges paid by storage affect the business case of the installation. Distribution network charges represent on average around 30 % (incl. VAT) of the final electricity bill in Europe, with a maximum of around 50 % in Norway and a minimum of around 15 % in Italy (ACER & CEER, 2018c). Network tariff design can encompass different modalities: capacity-based network charges, and volumetric network charges. The paragraphs that follow first define capacity-based network charges. Then, we define and compare the implications of three modalities of volumetric network charges: net-purchase volumetric charges, volumetric charges with net-metering and bidirectional volumetric charges. Finally, the conclusions of the study are presented.

With capacity-based network charges, a consumer pays for the grid according to his (individual) monthly or yearly peak capacity usage averaged per e.g. an hour. The idea behind capacity-based

[52] This section is an excerpt from (Schittekatte & Meeus, 2019), a study made for the STORY H2020 project.

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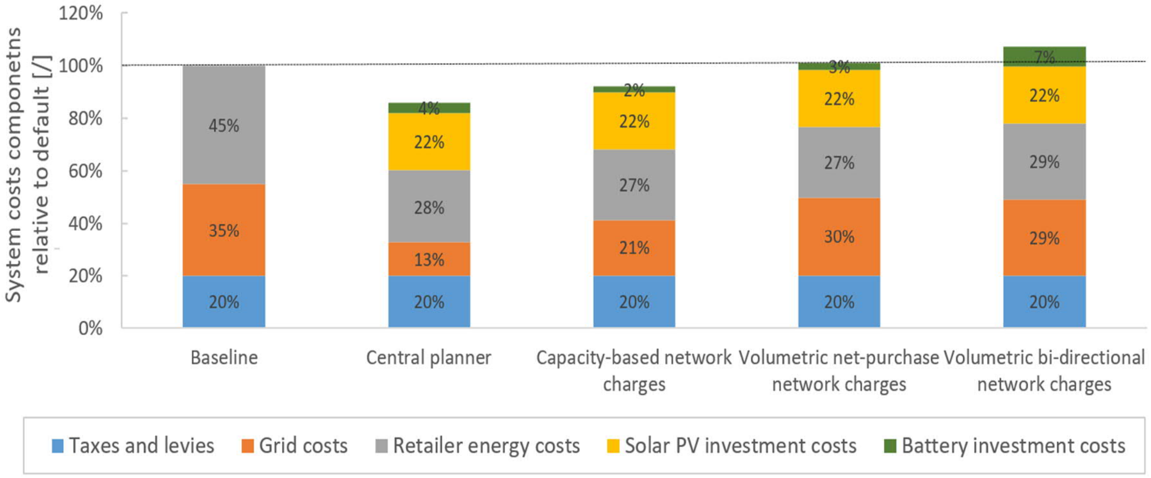

Figure 23: System costs and its components for the different network tariff designs

charges is that as the main driver of the network is (peak) network capacity, consumers ought to be charged according to their maximum network capacity needs. The problem is, however, that individual consumer maximum capacity-usage does not always coincide with the main network cost driver: the aggregated peak capacity needed over all consumers connected to the same network.

An alternative to the capacity-based network charges is the use of volumetric charges. In here three different options for volumetric charges are presented :

- Net-purchase volumetric charges: a consumer pays a network fee for every kWh withdrawn from the network
- Volumetric charges with net-metering: energy injected into the grid is counted as negatively consumed energy, so it is subtracted from the total amount of energy withdrawn. The traditional meters installed would run backwards when energy is being injected into the network from a consumer's facility.
- Bi-directional volumetric charges: energy withdrawn and energy injected into the network are metered and billed separately; a €/kWh network fee is paid for each kWh of electricity withdrawn and injected into the network. By creating a difference between the value of on-site generated electricity that is self-consumed or injected back into the network, this network tariff design incentivises self-consumption.

These definitions show that these charging methodologies can have very different effects on the incentives of batteries owners. On one extreme, net-metering charges do not stimulate self-consumption at all. With this tariff the grid acts as a free battery, and the price a consumer receives to inject 1 kWh into the grid is always equal than the price a consumer pays to consume 1 kWh from the grid. On the other extreme, bi-directional metering will give the incentive to minimise the exchange of electricity with the grid and thus to maximise self-consumption, if the network tariffs are designed properly. The incentive to self-consume under volumetric charges with net-purchase lies in the middle.

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To evaluate the effect of these charges structure on the overall costs of the system, this study introduced a game-theoretical model to capture the interaction between the distribution network tariff design, the decisions made by active consumers investing in PV and batteries and their aggregated effect on the network cost. The results are presented Figure 23. The first vertical bar presents the case that no active consumer invests in DER (baseline scenario). The following columns compare the findings for the other cases to those of the baseline scenario:

- Central planer: it represents the trade-off between the grid costs, retailer energy costs, solar PV and batteries for the given parameter settings. This combination of grid costs, retailer costs and investment in solar PV and batteries, lowers the sum of the interacting components of the electricity bill to a total system cost which is 14 percentage points lower than the baseline since a large portion of grid costs are avoided by the installation of solar PV and batteries.[53]
- Capacity-based charges: this case also leads to an investment mix which lowers the total system costs relative to the baseline. However, due mainly to an under-incentive to invest in batteries and sub-optimal operational signals, the grid costs are not decreased as much as would be optimal.
- Volumetric network tariffs with net-purchase: these tariffs lead to a total system cost with around the same value as the baseline, even though the composition of the different components is very different. Some batteries are installed, less than in the optimal central planner case, and they are not operated in a way that the grid costs are decreased. This happens because the network is being used as a battery, and therefore grid costs don't decrease as much as in other scenarios.
- Volumetric charges with bi-directional charges: this case results in a system which is more expensive than the baseline case without any DER investment. An overinvestment in batteries by the active consumers occurs. The active consumers are incentivised to increase self-consumption to a level which is not cost-efficient from a system point of view under the given assumptions.

From a grid perspective, there is little need for batteries and the main exercise is to find a network tariff design which remains acceptable in terms of distributional impacts while minimising any possible distortion. Examples can be found in e.g. Pérez-Arriaga et al. (2017), Pollitt (2018) and Wolak (2018): differentiated fixed network charges are not recovering all sunk grid costs through the electricity bill. In a preceding study, Schittekatte and Meeus (2018) show that spreading the grid costs over capacity-based charges, volumetric charges and fixed charges can also mitigate the induced distortions.

In the other extreme, still many grid investments have to be made, and the future grid costs are driven by the growing aggregated peak demand of consumers. Under this scenario, our model shows that in that situation the tested network tariff designs will not only give an inadequate investment signal to the consumers, also the consumers will operate their installed batteries sub-optimally from a grid point of view. If consumer electricity demand profiles are rather

[53] Taxes and levies are assumed to be invariable and recovered through a fixed charge which does not distort the decisions of consumers.

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homogeneous, batteries are under-invested by capacity-based charges. If consumer electricity demand profiles are heterogeneous, consumers will lower their individual demand which will have little effect on the system peak demand; a similar dynamic as in the sunk grid cost scenario occurs. With a network tariff design that encourages self-consumption, the business case of storage is unrightfully negatively impacted when the batteries are not coupled with onsite generation such as solar PV. Oppositely, when active consumers combine solar PV with cheap batteries or grid costs are high, an over-investment in batteries can result under the network tariff designs that encourage self-consumption. The batteries are fully charged with self-generated solar PV to increase self-consumption, but it can happen that by the time the system peak demand occurs, the batteries are already fully discharged again. In that case, a high capacity of batteries is installed, but they do not contribute to overall grid costs savings.

The study finds that the business case of batteries and overall system benefits are not always aligned. In one extreme, in the case where most grid costs are sunk and little future grid investment is expected, the evaluated network tariffs mostly over-incentivize battery adoption. In this case, network costs are simply transferred from active to passive consumers, and each investment in batteries by active consumers increases the (private) value of an additional investment in batteries.

8.4.3 Current Practices

A description of the current tariff designs in Spain, Belgium, Finland, and Austria is presented next. In Spain, consumers pay a mixed tariff consisting of capacity charges (€/kW) and energy charges (€/kWh) (Ministerio de Economía, 2001). In low voltage, users with a contracted capacity under 15kW can opt for a flat network tariff, or a stepped tariff with two or three different prices for the energy (kWh) consumed throughout a day. The tariff that differentiates three different prices is meant for users that have an electric vehicle. Users who demand over 15kW capacity must enter into a tariff with three daily price periods. Higher voltages can have up to six differentiated network tariff energy prices per day. In recent self-consumption regulation, self-consumers with excess energy who meet certain requirements can be compensated by their retailer for the energy they inject into the grid. The terms will vary depending on the bilateral agreement between the retailer and the consumer. Self-consumption with excess that can opt for compensation will be net-metered. However, those who will not receive compensation for their excess, must pay grid tariffs for the energy injected into the network. Self-consumed energy from renewable energy is exempted from tariffs and levies (Ministerio para la Transición Ecológica, 2019).

In Belgium, the electricity tariff scales mostly with the energy consumed kWh. Given that most Belgian households have classic meters, the most common tariff methodology is volumetric tariffs with net-metering. The price is mainly reflecting the energy consumption, together with a small connection cost. In Brussels, bi-directional meters are mandatory for customers with an electricity production unit. Further, the Flemish regulator is considering changing to a capacity-driven tariff mechanism.

In Finland, the DSOs are free to choose their tariff structures, however, to prevent abuse of monopoly power, the Energy Authority regulates and monitors the total turnover and return of the companies. In Finland the distribution tariffs of small-scale customers consist of a volumetric

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Box 1: Flexcity's's View on Tariff design

To flexcity, a combination of smart capacity-based network charges and volumetric bi-directional metering seems an optimal tariff type. The smart capacity based network tariff should not only be based on the maximum yearly demand peak but on the number and size of the 5 biggest peaks. This smart capacity based tariff would strike a balance between reflecting the real costs one puts on the electricity system and financially incentivizing household flexibility, which can be delivered by batteries. Capacity based network charges should come together with volumetric, bi-directional tariffs which incentivize to decrease overall electricity consumption.

\- Flexcity

charge based on transmitted energy and a fixed basic charge, which in some companies depends on the size of the main fuse. Some companies have incorporated a power-based cost component into the distribution tariff. This is considered justifiable especially from the viewpoint of cost-reflectivity and steering effects. In Finland, storage is tax free since April 2019. Electricity taxes used to be paid twice, first when charging the battery storage system, and second when using the electricity in consumption. The change in regulation is related to each situation, when electricity is transferred to the energy storage system and then back to the grid, then it is tax free. According to the tax law, a battery energy storage system which is part of a power plant does not need a license for tax free storage. The owner of a stationary electricity storage may apply for a license for operating a tax free storage, if the electricity is destined for consumption. The license application is made to the Finnish tax administration. The electricity fed back into the grid remains tax free until it is used for final consumption. The owner of the tax free storage is responsible for monthly and annual reporting to tax authorities. Today the DSO's are expected to apply the present tariff structures for battery energy storages due to absence of public tariff's tailored for storages only.

In Austria the tariff is mainly volumetric based. A local tariff for energy communities is being developed indirectly supporting storage. The plan is that for electricity shared only within the Energy community only low voltage volumetric grid tariff elements have to be paid, leading to a reduction of about 50% of the volumetric grid tariff elements. Also, other taxes and surcharges that are part of the grid tariff may be removed.

8.4.4 STORY Project Recommendation

The STORY project recommends that tariffs design should aim for grid cost recovery, technology neutrality, and separation of energy destined for storage vs final consumption. Each item is discussed next with additional discussion in Box 1 that presents the specific point of view of the STORY partner Flexcity.

Grid cost recovery means that grid charges should adequately recover the grid costs incurred by network operators. Capacity-based network tariffs incentivise consumers to lower their individual peak demand. The two other network tariff designs, volumetric net-purchase and volumetric bi-

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directional, result in a difference between the value of on-site generated electricity that is self-consumed and electricity that is directly injected back into the network. There is a trade-off between cost reflectivity and complexity. Detailed cost reflectivity implies more complexity, while tariffs that are too simple may not give adequate incentives. Spreading the grid costs over capacity-based charges, volumetric charges and fixed charges can help mitigate possible distortions.

Tariff design should be technology neutral as tariffs should aim to legislate for service provision or consumer behaviour in general. A first step in this direction is, for example, the Spanish approach, which regulates self-consumption (including storage) rather than specific technologies.

For storage facilities directly connected to the network, legislation should make a distinction between energy stored for service provision and energy destined for final consumption. It is the view of the STORY project that energy stored for service provision should not pay the taxes and levies imposed on energy destined for final consumption.

8.5 DSO Participation in Storage Projects

In the Background subsection DSO participation in storage projects is discussed from a practical and a regulatory point of view. The practical point of view includes potential problems stemming from DSO participation in storage projects but also current practice and possible exceptions. In the second part of this section recommendations based on the activities and finding of the STORY project are defined.

8.5.1 Background

Integrating storage into the system poses technical challenges regarding the behaviour of the storage technology, safety over the connections and considerations on grid requirements. These factors make it necessary for DSOs to get involved in storage projects. The main role of a DSO should be to facilitate the interactions of market players and consumers while maintaining a safe and reliable grid.

The clean energy package places the ownership and operation of storage facilities in the hands of commercial parties with some exemptions in specific cases (European Parliament and the Council of the EU, 2019). The Suha Demo in the Story project sheds light on what may constitute an exceptional situation. To present background information this section summarises the main points of these regulations. More concretely, this section considers as an example the regulatory decision of Ofgem, the EU Clean Energy package, and finally discusses what constitutes an exceptional situation where DSOs may operate storage.

Ofgem has identified that ‘where flexibility assets are owned and/or operated by network operators there is potential to distort competition in markets for flexibility services or deter new entrants’ (UK Department for Business Energy & Industry Strategy & Ofgem, 2018). As a result, Ofgem has added a new condition in the electricity distribution licence such that distribution network operators are ‘prohibited from carrying out any generation activities (including storage), unless the activity is captured by an exception or the licensee has been issued with a direction’ (Ofgem, 2018). The decision is related to the operation of storage assets, and does not extend to ownership. Therefore, under

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this ruling, network companies may own but may not operate storage assets unless they have been granted an exemption.

Article 36 in the Clean Energy Package directive on common rules for the internal market goes a step further and states that 'distribution system operators shall not be allowed to own, develop, manage or operate energy storage facilities' (European Parliament and the Council of the EU, 2019). The article then goes on to state an exception where DSOs may own, develop, manage or operate energy storage facilities which are 'fully integrated network components and the regulatory authority has granted approval'. In the same Directive, in Article 32, DSOs are mandated to publish a network development plan every two years. The network development plan should include the use of demand response, energy efficiency, energy storage facilities, or other resources as an alternative to system expansion. This regulation makes it clear that DSOs are expected to be network facilitators who will procure flexibility services from market parties.

The cases when an exemption may be appropriate are discussed. Storage being a new technology, DSOs are not yet sure of how and what services can be expected from such a facility. In the STORY demo case in Suha, the DSO directly operates a medium scale storage unit of 170 kW, 450 kWh. This unit is used in network load management and power balancing, power quality, peak demand control, reduction of line congestion, and avoiding PV curtailment. It is the first system of its type to be installed in Slovenia and the DSO had to make significant efforts to adapt their grid management systems to accommodate the battery. Through the demo, Elektro Gorejnksa is learning the possibilities and limitations of the technology. As a pilot project it is providing valuable information that may later be translated into commercial service requirements. Article 36 quoted above, outlines that a DSO may operate a storage facility when no acceptable bids have been obtained after a tender procedure. The pilot done in the STORY project provides the DSO with information that can help them structure a tender procedure in the future and further define technical requirements enabling the future flexibility market. See Box 2 for more details on the Suha demo, and the position of Elektro Gorejnska on the topic. In conclusion, in exceptional situations, it may be useful for DSOs to operate storage as a learning process to be able to later facilitate commercially owned storage systems.

8.5.2 STORY Project Recommendation.

The STORY project proposes three main recommendations: storage assets should be operated by commercial actors, the DSO should have procedures to integrate the operation of these assets and the DSO should follow a balanced process when choosing between network reinforcements and new storage solutions.

Storage assets should be owned and operated by commercial actors. The storage market is yet immature and commercial parties should be able to valorise their assets by offering services where they add the most value. This may be for internal electricity savings, or for service provision to a DSO, TSO or another market actor who may need it. Storage ownership and operation by a DSO could distort competition thus limiting the possible revenues that market parties may earn. It is important to make a difference between ownership an operation. Ownership of storage by a DSO should be an exceptional situation, where commercially owned storage is not available, but operation could be possible under service agreements. Under normal circumstances, appropriate

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channels should be enabled, to allow the DSO to contract flexibility services and send signals to a storage owner when needed.

Allowing DSOs to exceptionally operate a storage system as part of their network assets could serve two purposes:

> 1/ DSOs who have had experience operating a pilot storage project will be able to provide a better service as network facilitators for commercial projects. This will avoid large time delays that a small company may not be able to accommodate.
>
> 2/ A DSO can learn and define what services can be expected from a battery to create appropriate service tenders.

DSOs should have procedures that enable the efficient connection and servicing of a new storage facility into the network. For example, the lack of standard procedures in the STORY Oud-Heverlee demo has caused significant time delays in the deployment of the neighbourhood battery. In this demo, the DSO was not involved in the STORY project. In contrast, in the Suha Demo, the DSO was fully involved in the connection and setup of the battery. Even in that case several issues had to be solved on a day to day basis to get the battery to be operational, and once operational to be able to run it smoothly. Elektro Gorejnska and ABB, the technology provider, had nearly daily exchanges of information during several months for troubleshooting.

As a result, the DSO should evaluate the grid impact of the local battery energy solution and control. DSOs must study the value of using flexibility versus network reinforcement. Only then will they be able to draft clear service definitions up for tender. Flexibility is an instrument that will allow network operators to connect more decentralised production, and eventually electric vehicles, into the network while maximizing the use of the existing infrastructure. It is a challenge to correctly compare the value of flexibility versus physical grid reinforcements. Methodologies to calculate the value of flexibility, and thus the services that a DSO will tender for, are necessary.

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Box 2: SUHA Battery as a fully integrated network Component for the DSO

A medium scale storage unit (170kW, 450 kWh) is connected to a distribution substation in Suha, a residential village grid. The unit is connected to a 400 kVA OLTC MV/LV transformer station of Elektro Gorenjska (EG). The substation low voltage network entails seven PV locations and nearly 90 households. The grid experiences flows in both directions due to the PV generation. There is 210 kWp of PV installed across seven units in the area.

From the DSO's point of view, a fully integrated network component represents the equipment providing DSO services, being an integral part of DSO regular technology systems and completely operated by the DSO. The Suha BESS demo system utilises EG network and control equipment used on a daily basis. It is also fully integrated into the EG SCADA network control system on demonstration (but not production) level due to sensitivity of BESS operation.

The BESS control algorithm very efficiently manages (minimises) MV/LV distribution transformer loads and by doing that effectively compensates local PV surplus production. Some additional functionalities are handy (reactive power compensation, THD compensation) but are not vital or necessary needed for the Suha demo explicitly. Beside functionalities available, islanding will maybe be a step ahead in future storage utilization.

If an aggregator provides a service, the DSO will be one of his customers, among the TSO, and local communities as well. If the DSO service would not be the most important service in the aggregator's hierarchy (which will be most likely strictly financially based), it could happen, that those services would not be available for the DSO when needed or even would have the opposite effects on network operations serving other purposes. This is also one of the reasons, why storage should be in special cases allowed to be owned and operated by DSOs.

The figure below presents an example of a sunny day where the transformer performs load compensation. The upper diagram shows real time measurements, the lower diagram represents algorithm calculations. The green line would be a transformer load without BESS connected, the white line is the transformer load compensated by the BESS, the purple line represents the BESS charging and discharging levels, and the blue line represents the battery state of charge level.

-Elektro Gorenjska

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8.6 Market Design

This section starts with the background sub-section that explains the balancing market from the point of view of the technologies that can provide flexibility and small prosumers. The section concludes with the STORY project recommendations for the market design changes.

8.6.1 Background

Two main aspects of market design are discussed in this section. The first is the design of balancing markets to allow the participation of flexibility coming from different types of technologies; the second is access to markets for small consumers through aggregation.

8.6.1.1 Balancing Market Design

Storage technologies have capabilities to provide services to grid operators or other market actors. Specifically, storage is capable of providing ancillary services to TSOs in the reserves markets, and potentially to DSOs in the future. These markets have been designed with traditional generation in mind but current legislation opts for technology neutrality in market design. First, the dispositions at a European level regarding technology neutrality in balancing market design are outlined. Second, the openness of balancing markets to different types of assets is discussed.

First, legislation at EU level regarding balancing market design is discussed. The Clean Energy Package, in the internal regulation for energy markets, article 6-1 states that 'Balancing markets, including prequalification processes, shall be organised in such a way as to ensure that services are defined in a transparent and technologically neutral manner and are procured in a transparent, market-based manner' (European Parliament and the Council, 2019). European legislation acknowledges thus the importance of transparency and technologic neutrality in balancing market design. The same article also states that balancing markets should 'ensure effective non-discrimination between market participants taking account of the different technical needs of the electricity system and the different technical capabilities of generation sources, energy storage and demand response.' The regulation must be applied by EU countries, which may require a redesign of balancing markets.

Second, to illustrate the practical implementation of these requirements, we discuss the following examples regarding technology neutrality:

- In Belgium, the effects of this legislation can be seen in the opening of the aFRR balancing market. Currently, at the time of the writing of this brief, this balancing service can only be delivered by CCGT, with plans to open the aFRR services towards non-gas powered assets as demand-response units and batteries. In Belgium the TSO ELIA has an ambitious timeline to reform the current FCR, aFRR and mFRR products. All changes which would, be implemented are aimed at improving the market accessibility (shorter tender periods, 4-hour granularity,...) and technology neutrality.
- In the UK, in contrast, an enhanced frequency response (EFR) service was tendered by National Grid, the TSO, in 2016. This product was aimed primarily at battery storage, catering to their fast acting capabilities to respond to system needs. In 2020, this technology

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Box 3: The BESS as a Service and it's role as an aggregator
Fortum owns and operates a BESS, which will be installed in distribution system operator's (Elenia) grid area in Kuru, in North Pirkanmaa. The BESS will be connected to Elenia's medium-voltage network and the batteries will supply electricity to a limited grid area during a power outage. This makes it possible to keep the electricity running in a limited area during repairs. In normal situations, the BESS will function in the reserve markets as part of the Fortum Spring virtual battery along with thousands of household electrical hot water heaters. The capacity of the virtual battery is offered to the transmission system operator's (Fingrid) reserve markets as regulating power. In Finland there are a few aggregators (Fortum Spring, e2m, Sympower) who are doing business selling flexibility but they are still evaluating different independent aggregator models and the wider impacts on electricity markets as well from technological as well as from regulative aspects.

-VTT

specific view is now being redesigned into the 'dynamic containment' response service, capable of responding within one second to frequency deviations. According to National Grid: 'this new

product is a step up in capability from EFR, and while open to battery providers initially, it will in the longer term widen the range of possible providers ' (National Grid, 2020).

- In Finland, Fingrid and other Nordic TSO's have outlined a need for fast acting reserves during frequent low inertia operating conditions. Operating conditions with low inertia have become more frequent in the Nordic power system, and at times the inertia is so low that the current reserve products alone are not fast enough. Therefore, the Nordic TSOs are currently implementing FFR (Fast Frequency Reserve) to handle low inertia situations with a plan to have the new reserve in operation by summer 2020. While the product is not technology-specific, batteries easily fulfil the service requirements (Fingrid, 2019). An illustrative example of a battery system providing services to the DSO and TSO in Finland is provided in Box 3.

8.6.1.2 Access to markets for small prosumers

This section discusses market design considerations that enable small prosumers to valorise their flexibility coming from storage. These considerations can be explained by considering how prosumers can valorise flexibility from storage at a local level by saving on their electricity bill and by participating at a wholesale level through aggregation. This section also discusses the importance of setting a baseline for flexibility services given that the economic value that can be reaped from flexibility is dependent on it..

One example of how prosumers can valorise flexibility can be observed in Spain. In the self-consumption legislation introduced in Spain in 2019, a self-consumer with excess production, and with an installed capacity of less than 100kW is entitled to a simplified compensation, the retailer ought to pay the consumer for energy fed into the network. The price is to be agreed between the retailer and the consumer. A self-consumer with an installation bigger than 100kW total power

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needs to be registered as a generator and is entitled to sell energy in the wholesale and balancing market.

From a system point of view small consumers can add value when they are aggregated. The clean energy package directive for the internal market states that members states should enable 'the right for each aggregator to enter the market without consent form other market participants' (European Parliament and the Council of the EU, 2019). Access to markets for small consumers is paramount for the business case of storage.

Consumers participate in electricity markets through intermediaries. Until recently they participated as electricity buyers through their retailers. Now, prosumers can sell energy and flexibility in the market through a new intermediary called an aggregator. The introduction of a new intermediary between the consumer and the electricity markets creates friction with the existing retailer. The independent aggregator modifies the consumption profile of consumers already served by a retailer.

It has been shown in STORY deliverable 'D8.2 Intermediate reporting' that retailers and aggregators have an inherently different core business model. A retailer is a dealer-type of business while an aggregator is a platform-type of business. Aggregators are defined in the Directive of the European Parliament and of the Council on common rules for the internal market in electricity (from now on 'the directive') as a 'market participant that combines multiple customer loads or generated electricity for sale, for purchase or auction in any organised energy market'. Two main issues have been identified that affect the development of the flexibility business by aggregators: information exchanges between the aggregator and a final consumer's BRP and unharmonized rules regarding the transfer of energy payment from the aggregator to the BRP.

One challenge that has been identified to incorporate the flexibility coming from prosumers into the energy system is the need to calculate a retribution system that accounts for the actual flexibility they deliver. More concretely, it is necessary to calculate the changes in behaviour as a result of a demand response program. To deliver this calculation, it is necessary to set a baseline in demand response that sets the load that users would have consumed in the absence of a demand response program. Storage is one of the technologies that consumers could use to deliver demand response. The baseline is important because payments for demand response are directly based on the difference between the baseline and actual metered demand. There are several different methods proposed to establish the baseline that can be grouped into three categories: statistical approach with adjustments, last X of Y, meter before/ meter after. The variety of methods proposed has policy implications given the amount of demand response calculated may vary depending on the method used. A policy that clearly outlines principles to build a baseline would serve to clearly define the demand response product. In turn this would homogenize the expected profit gained by demand response providers.[54]

The theory has evolved significantly throughout the past 10 years. To consider the robustness of this theory we compare practices in selected countries to the theory. In this comparison, it is found, that the practices regarding baseline setting in Europe have not caught up to the academic theory due to difficulties in measurement and real-time implementation. The difficulty in the practical application of this methodologies arises from the lack of readily available data to calculate the

[54] Excerpt from (Ramos, 2019)

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baseline appropriately taking seasonal and situational variations into account. A paper written in WP8: 'Consumer access to electricity markets: the demand response baseline', examines both the theory and the practices regarding baseline calculation.

8.6.2 STORY Project Recommendations

The STORY project proposes two main recommendations for market design: technology neutrality in service design and assurance that consumers are enabled to valorise flexibility.

The STORY project considers that technology-specific products can distort the market towards a specific solution. This distortion could mean that new technology cannot compete/be adopted as they cannot participate on a level playing field. Grid operators should strive to make specific service definitions in terms of time granularity, bid size, and location in the case of distribution grids. Storage is a technology that can enable consumers to offer flexibility services, and ought to be considered within the wider scope of flexibility procurement by system operators.

The business case for storage facilities largely depends on being able to stack revenues. Storage asset owners that can provide flexibility to the network should be able to valorise their contribution. A retailer can remunerate, or rebate, a consumer's electricity bill when electricity is injected into the network; following the example set by the self-consumption regulation in Spain. An aggregator can pool and valorise the final consumer's flexibility in the electricity markets where they are most valued (balancing, DSO services, etc…). Smart meters that enable remote monitoring and control of loads are essential to enable prosumer participation into markets. Fair management of data from smart meters is similarly relevant. To create a level playing field for aggregators the relationship between third party aggregators and balancing responsible parties needs to be clarified in terms of information confidentiality and transfer of energy payments between both parties need to be harmonized across different markets.

8.7 Business Models

The background of the business model discusses different value streams that can be created by storage aggregation models. This section concludes with specific STORY project recommendations.

8.7.1 Background[55]

A mapping of the business models in the STORY demo was carried out through a series of three workshops during 2018 involving the demo leaders and other project participants[56]. Error!

[55] This section is an excerpt from D8.2 Intermediate Reporting for Story, Advisory Board and Projects Council, Chapter 4.

[56] The three internal workshops mentioned consisted of defining the business model canvas for each demo within the project, representatives or STORY H2020 partners were present at each session, including an aggregator, demo leaders and technology providers. Two workshops took place during the story general meetings in April and October 2018; while the third workshop took place in Brussels in November 2018. In addition, an advisory board workshop

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Figure 24: Business Model Archetypes in the STORY project

Reference source not found. presents a mapping of the demos comparing the value they create and the level of aggregation of the resources. Participation in different markets is related to project size and aggregation of resources. The main value categories refer to:

- Savings for the owner are achieved when storage technologies enable an in-house optimization by storing renewable energy when available or storing energy from the grid at specific times of the day when it is cheaper. The saved energy is then used at an optimal time when the energy provided by the grid is more expensive. In the STORY project the Navarra, Oud Heverlee Building (OHD building), Olen and OHD Neighbourhood (Nbhd) demos include strategies and systems that enable them to do in-house optimization to decrease the energy bill. Box 4 the experience of the Oud Heverlee neighbourhood demo.
- Services to DSO & TSO refer to either reserve energy that can be provided for balancing the network or services for voltage stability and power quality. Balancing services are specifically FCR, aFRR, and mFRR, also known as primary, secondary, and tertiary reserves traditionally procured by TSOs. It has been shown in STORY that the OHD Nbhd, Suha and Lecale demos can provide value for the DSO. They can offer power quality support for the local grid. However, it is not possible to monetize this value in every case. In the OHD Nbhd case, the acting DSO has not defined products for power quality that would receive remuneration. Therefore the value is purely theoretical at the moment. See Box 4 for a description of the barriers encountered in this demo. In the Suha case, the DSO itself is steering the battery and can measure power quality improvements which can contribute to

was held in Slovenia in October 2018, it consisted of 14 professionals in the energy sector invited to provide their opinion on business models for storage, and related technologies.

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grid investment deferral. The Lecale case could provide services for both the DSO (congestion management) and the TSO (balancing energy).

- Market arbitrage refers to trading energy in long term, the day-ahead, and real time spot markets to help market players balance their portfolios. Market arbitrage with a storage unit consists of buying energy at a time when it is cheap and storing it to sell later at a time when it is more expensive. The Lecale demo would work with an aggregator to participate in the electricity market in Northern Ireland. The Lecale demo would offer load on-demand services for a local wind power plant that often gets curtailed due to grid congestion.

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Box 4: Oud-Heverlee Neighbourhood Demo

This demonstration features 13 houses in Oud-Heverlee which are developed towards an energy community. The aim was to demonstrate the synergy of a neighbourhood strategy for flexibility and grid balancing. In order to accomplish this, everything in the neighbourhood that can store energy is monitored.

The specific STORY case of residential smart home management faces the largest market barriers which today make it impossible to realize any meaningful part of its economic potential. For almost every potential value stream, one or more barriers stand in the way to realize its potential and barriers are present on every level of the supply chain: TSO, DSO, Supplier. The benefits of the project towards the DSO is that the project minimizes grid exchanges, has the potential to reduce required grid investments by addressing congestion issues and improves the power quality which is today lacking due to the fact that the residential neighbourhood in question is at the end of the distribution line. The value generated however cannot flow back towards the end customer as there are no local flexibility markets organized on which the value of the flexibility can be monetized nor does the DSO tariff give any incentive.

The potential of the project towards the TSO is that the flexibility could be offered as balancing service. Primary and tertiary reserves can be offered with heat pumps, electrical boilers and local storage. There are however two important barriers: the metering requirements put forward by the TSO would require investments which cannot be carried by the revenue streams they would generate. Also the minimum volume that needs to be bid for these services is 1MW, very high from the perspective of these energy communities. A solution for the first issue could be the roll-out of smart meters by the DSO which would meet the qualifications of the TSO thus making every household a potential flexibility supplier. The second element would require the participation of an aggregator.

Lastly the flexibility of an energy community can also be beneficial to the supplier/BRP as the consumption and (renewable) injection of the community could be optimized based on both the day-ahead prices and in intraday towards the imbalance price. There is however a cascade of complex barriers to overcome before the generated value could stream towards the energy community. Before energy communities can profit from changing day-ahead and intraday or imbalance prices they need to receive an exposure to these prices. An exposure to wholesale markets of the consumer can traditionally be created by the energy supplier who can link the energy tariff to market and imbalance prices. However, a supplier will only be able and willing to expose residential customers to these markets when they themselves can, back to back, expose the consumption of these residential customers to these markets. This will require the roll-out of smart meters and the implementation of new allocation rules which correctly allocate the consumption and injection of residential consumers towards the correct supplier. This would require that TSO's, DSO's and suppliers would be able to generate/measure, store and process large amounts of data as for every consumer two quarter hourly values would need to be known: the offtake and injection.

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8.7.2 STORY Project Recommendations

The STORY project has three main business model recommendations. In addition, Box 5 presents the view of STORY partner Flecity on incentives for storage.

- First, the business model for storage depends largely on being able to stack revenue streams coming from either, energy savings, services to system operators or services to other market parties. The potential of a specific project are defined by its technical characteristics. Energy savings can be maximised when a consumer is exposed to varying market prices, both on the energy and grid tariff component. Larger storage facilities have the potential to offer services to system operators directly. Smaller household consumers are currently facing limitations due to the need to comply with market metering and participation requirements. The STORY project has proven that storage assets have the potential to offer services to both distribution and transmission system operators.
- Second, the aggregation of resources is key to enable the value of the flexibility that can be provided by residential consumers. Consumers now can also sell energy and flexibility though at a much lower scale than conventional generation. However, they find that the mechanisms to do so are not available and, as a result, the potential flexibility from smaller consumers is not being reaped. Storage project developers find difficulties in securing long term revenue streams. Energy communities and individual household consumers who have a flexibility potential need to partner with intermediaries who have access to markets. Similarly, smart meter availability is key to reap flexibility from final consumers.
- Third, clear product definition, especially from the DSO perspective is necessary to enable a business case for smaller local flexibility providers. Flexibility services offer value for society when their use would defer grid investment. DSOs need to define technology neutral service tenders that enable prosumers or their intermediaries to valorise their flexibility. More study is needed from the point of view of the DSO to evaluate when and under what conditions flexibility is a better option than grid investment.

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Box 5: Flexcity on incentives for storage

Flexcity prefers indirect incentives over direct incentives for storage. The European commission defined three main parameters on which direct state aid should be assessed and direct aid for batteries does not meet any of these criteria according to our analysis. The first question to be asked is if the state aid is aiming at a clearly defined objective of common interest. Especially in this case, the state aid should address a market failure, where for example external, environmental costs are not accounted internally. In our opinion, there is currently no market failure in the flexibility market which justifies the support for specifically the battery technology. However, we see a market failure in the accounting of grid costs, so we think direct support for household flexibility would be justified based on this parameter. The second question to be asked is if the aid is well designed to meet the objective. This means that first other instruments like indirect incentives should be examined (as in this case, redesigning grid-tariffs).

Moreover, the subsidy should be designed to change behaviour fundamentally. This was not the case with the current Flemish battery subsidy, which did not render a battery investment profitable. The last question to be asked is if the aid does not distort competition or trade. This means that everyone should have equal access to aid.

Based on these three parameters, as defined in European law, Flexcity does not consider direct aid for batteries as desirable. We think that batteries should be seen as a measure to achieve a flexible power system, not as a goal on itself. Storage can benefit from indirect support such as identifying and removing barriers of participation to ancillary services, creating and testing new flexibility markets as local congestion markets to increase the number of services a battery could get revenues from.

- Flexcity

8.8 Conclusion

The STORY project has identified five main areas of discussion regarding business models and regulation for storage: legal definition of storage, network tariffs, DSO participation in storage projects, market design, and business model enablers.

Technology development is moving forward at a faster pace than markets and regulation can adapt. The project developers that led the demos in the STORY project faced the challenges of an immature market. Technology providers were slow to fulfil their promises, system integration and interoperability ended up being a bigger challenge than expected, and in many occasions the demo leaders were pioneers in permitting and connection procedures with their local authorities. The recommendations set in this document reflect real-life challenges faced by project developers when bringing new technology to the market.

Storage technology is a key factor that will enable the large-scale integration of renewable energy into the system, and the decarbonization of transport. The results of the STORY project pave the way to enable the storage market to grow in a commercially viable fashion.

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9 Acronyms and terms

DSO		Distribution system operator
TSO		Transmission system operator
BESS		Battery Energy Storage System
JRC		Joint research centre
FSR		Florence School of Regulation.
EC		European Commission
OLTC		On load tap changer
I-SEM		Integrated Single Energy Market
NIE		Northern Ireland Electricity Networks
IP		Intellectual Property
MV		Medium voltage
LV		Low voltage
PV		Photovoltaic
RES		Renewable Energy Sources
SMEs		Small and medium enterprises

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