Aggregated Flexibility to support Congestion Management

A case study at Eneco CrowdNett



Aggregated Flexibility to support Congestion Management

A case study at Eneco CrowdNett

Master thesis submitted to Delft University of Technology

in partial fulfilment of the requirements for the degree of

MASTER OF SCIENCE

in Complex Systems Engineering and Management

Faculty of Technology, Policy and Management

by

Robin Brouwer

Student number: 4329406

To be defended in public on February 16th 2018

Graduation committee

Chairperson	: Prof. Dr. Ir. Zofia Lukszo, Engineering Systems and Services
First Supervisor	: Dr. Pieter Bots, Multi Actor Systems
Second Supervisor	: Dr. Ir. Laurens de Vries, Engineering Systems and Services
External Supervisor	: Fredrik Troost, Senior Structurer at Eneco Energy Trade B.V.

Cover images were retrieved from Solar Directory and PROECO S.r.l

Preface

The recurring topic of changing energy systems throughout my studies sparked my interest and has driven me to the point I am now. The SEPAM program (currently CoSEM) introduced me to the various aspects of the energy system from a theoretical perspective and motivated me to gain some practical experience within the industry before graduating. It led me to the beginning of 2017 where I started an internship within the Eneco Group. After six interesting months at the Corporate Communications and Public Affairs department, Fredrik Troost offered me the opportunity to write my thesis within the business unit Eneco Energy Trade (EET). The topic appealed to me directly and marked the beginning of the final test of my master program.

Personally, I think it was a very challenging process, yet a very exciting and valuable learning experience. There were times I felt like sprinting the marathon in under two hours, but there were also times I felt frozen on a single spot. Fortunately there were various groups of people helping me and pushing me through, from roommates cooking dinner for me, to having some drinks with close friends, to meetings with members of my graduate committee.

I would like to thank Fredrik, being my external supervisor from Eneco, for guiding me through the project via our weekly meetings where he really supported me with the practical side of the project. The personal lectures regarding the technical details of the product, the long-term strategy, and lessons learned during the project are very much appreciated, as well as some informative discussions about other projects in development at EET.

I would also like to gratefully acknowledge Pieter Bots from the TU Delft, who has been my first supervisor to this thesis research. His in-depth knowledge of the software and huge backpack of modelling experience allowed me to quickly move towards the core of this research. Thank you for the fun and valuable discussions, where forgetting the time by an hour on Friday afternoon was not unusual. Likewise, I would like to thank Özge Okur who supported me throughout the project as a so-called daily supervisor. Her scrutiny and efforts to always read my draft material is very much appreciated. Finally, I would like to thank Laurens de Vries for providing helpful suggestions from an economic perspective and Zofia Lukszo for reviewing and positively confirming my intermediate results, both helping me to finish the project on time.

Altogether I can say that I am very proud of the end product that lies in front of you. It marks the end of a remarkable time as a student in Delft, and I am sure that the skills and knowledge gained throughout these years will be valuable for my first challenge as Junior Energy Consultant at Sia Partners as well as for the remainder of my professional career. Moreover, I hope that it supports Eneco CrowdNett and other interested parties in our shared responsibility to find innovative ways to transition to a more sustainable power system.

Robin Brouwer

Delft, February 2018

Executive Summary

Increased variable renewable energy sources penetration in The Netherlands require more flexibility that could be provided by Distributed Energy Resources (DERs) located at small end-users combined with demand response. Aggregators could act as intermediary entities to exploit the flexibility potential of small end-users and create value for Distribution System Operators (DSOs) by delivering electric flexibility services that support, among others, congestion management.

The value that an Aggregator's electric flexibility services may create for the DSOs is still unclear as it depends on many factors. First, there is a strong dependency on the type of assets located in a low-voltage (LV) distribution grid. Second, that same LV distribution grid could have many different configurations in terms of substation capacities and transport cables. Then, once value is created, how much value can be captured by whom is also dependent on many exogenous factors such as electricity prices, technological advancements, government policies and regulations.

Aggregator Eneco CrowdNett is planning to commission a pool of households which will have a combined system of solar-PV and residential Battery Energy Storage (BES) units. Next to optimizing the household's self-consumption, these systems will jointly be able to deliver power to the grid. Therefore, the system as designed by Eneco CrowdNett will be used as a case-study during this research.

This research aims to provide a comprehensive understanding of how the value of an Aggregator's electric flexibility services can be determined for DSOs, without jeopardizing the business case for the Aggregator and the CrowdNett participants themselves. The main research question is therefore as follows:

How can the value of Eneco CrowdNett's electric flexibility services, provided by BES units connected to the LV distribution grid, be determined for DSOs?

This question asks for a methodology rather than a quantitative result. Therefore, a tool that simulates the behavior of residential BES units connected to the LV distribution grid is developed and tested on a specific case, followed by a reflection on its usability for other cases.

The system under review in this study is framed as a Unit Commitment Problem (UCP), in which the generation units are represented by CrowdNett's residential BES units that primarily deliver local service, but can also deliver congestion management services through load shifting. The Self-Consumption Optimization (SCO) service allows end-users to store their surplus PV electricity for other moments in time. It commits BES units to either charge or discharge based on the local conditions in the in-house grid. Similarly, load shifting services ensure that BES units charge or discharge according to the congestions in the grid. Linear Programming (LP) is considered a useful method to solve the identified UCP. It is implemented in the modelling software Linny-R.

The neighborhood of Kijkduin just outside of The Hague is selected as a representative LV distribution grid in The Netherlands based on a literature study. It consists primarily of large detached houses connected to 4*95 [mm^2] and 4*50 [mm^2] copper cables fed through a substation of 200 [kVA]. The total number of connections to the substation is 111.

In the first phase of the research, the perspective of end-users is analyzed by means of the Linny-R tool. It shows that end-users can offer at least 3 to 4 [kW] of power capacity, and similarly offer 3,5 to 7,5 [kWh] of energy capacity to the Aggregator while still ensuring the economic viability of the BES unit investment.

Subsequently, the Aggregator's perspective is analyzed by means of the Linny-R tool. It shows that a 60% PV penetration is the threshold value before the business case of the Aggregator becomes jeopardized by congestions. The number of expected congestions at higher PV penetration levels increases, yet the number of so-called congestion weeks remains roughly the same.

The DSO's perspective is reviewed by analyzing the costs of congestion management via the traditional grid reinforcement method and via load shifting through the Aggregator. Starting with the former, key figures expect the total costs of grid reinforcements to range from 100.000-200.000 [€]. This depends on the required conductors and life expectancy of the assets, which a Net Present Value calculation values at 5900 to 9000 [€/year] of required future cash flows. The other option, load shifting through the Aggregator, has been found to be significantly cheaper. The Linny-R tool simulations showed that only 2.2% of the total PV production in the grid needs to be curtailed in order to satisfy the demand of all end-users when a BES unit is added to each PV-system.

The system perspective is analyzed during the last phase of this research. It is found that utilizing the Aggregator for congestion management, rather than traditional grid reinforcements could reduce the total system costs with 6200 to 42100 [€/year], corresponding to -12,8%. This is primarily caused by the additional income via the Primary Control Reserve (PCR) market, the reduced power extracted from the grid, and the corresponding reduced energy taxes. End-users capture this value through a total cost reduction of -1,3%, whereas the Aggregator is able to realize an additional 3% of profits under the assumed market conditions in the case study.

Regarding the identified values for each actor, it is fundamentally difficult to assess the value of residential BES units for one actor in the supply chain exclusively by means of optimization. Rather they reveal the theoretical maximum values that could be captured by each actor. Whether and how much value is actually captured by end-users and the Aggregator depends on market dynamics such as wholesale price developments, pricing rules, competition between Aggregators, and contract negotiations.

The results of this study have therefore been scrutinized in the final phase as well. Especially the PV production profiles are considered an uncertain factor affecting the outcomes of the Linny-R model simulations, since those are the sources of congestion problems. Moreover, the study focused on the potential congestions at the LV substation and neglected any possible congestions occurring at the underground conductors.

The market and policy developments in terms of electricity prices and financial support schemes may also affect the results, yet these are expected to be in favor of end-users from an economic perspective and do not influence the expected congestions. Furthermore, DSOs have to carefully consider the implications of competition between Aggregators and utilities for two reasons. First, the congestion services provided by the Aggregator require information about the grid configurations, but more importantly she should have the ability to accurately forecast the expected loads in the grid which is usually the task of the utility company.

Based on these insights, it can be concluded that the Unit Commitment model is able to simulate the behavior of BES units located in a LV distribution grid, yet the costs of congestion management depend on the local conditions of each particular grid. Besides, the outcomes of the simulations strongly depend on the implications of the methodology, the selected case study and the other assumptions.

Thus, referring back to the main research question, the value of Eneco CrowdNett's electric flexibility services for DSOs can therefore *not* be determined by exclusive using a Unit Commitment model with a LP solver to replicate the behavior of residential BES units located at the LV distribution grid.

The model rather provides a tool to generally assess whether an Aggregator is able to reduce congestions in a given distribution network without jeopardizing her own business case and that of the end-users owning the BES units. The model should be supplied with input data regarding residential demand profiles, PV production profiles and the power capacity of the LV substation before the model output can be compared with the expected costs of grid reinforcements on a case-by-case basis to determine the value for DSOs.

With the insights provided in this report, a contribution is made towards the need for designing of congestion management mechanisms to postpone or even avoid the need for costly network capacity upgrades as highlighted by Verzijlbergh et al. (2014). This is especially relevant because Veldman (2013) highlighted that 87% of all MV/LV substations in the Netherlands are expected to be overloaded by the time of 2040. It does so through progressing the readers understanding on this subject by:

- Demonstrating the possibility for owners of residential BES units to share their asset with an Aggregator without compromising their own business case
- Demonstrating the ability of an Aggregator to reduce the congestions originating from PV-systems through load shifting services, as long as sufficient information about the LV distribution grid is available
- Assessing a particular case study of Eneco CrowdNett and LV distribution grid Kijkduin and showing that additional value to the system as a whole can be created by an Aggregator
- Developing an easy-to-use optimization model to generally assess whether an Aggregator is able to reduce congestions in a given LV distribution network without jeopardizing her own business case and that of the end-users owning the DERs

Table of contents

1 Introduction

1.1 Changing Power Systems

Variable Renewable Energy Sources (vRES) are increasingly penetrating the Dutch electricity grid causing more intermittency due to weather-dependent production patterns. In order to cope with the additional uncertainty, more flexibility is needed. The balancing equation as presented in IEEE power & energy magazine (see figure 1), provides an effective overview of the sources of flexibility and variability, and the systems integrating them.

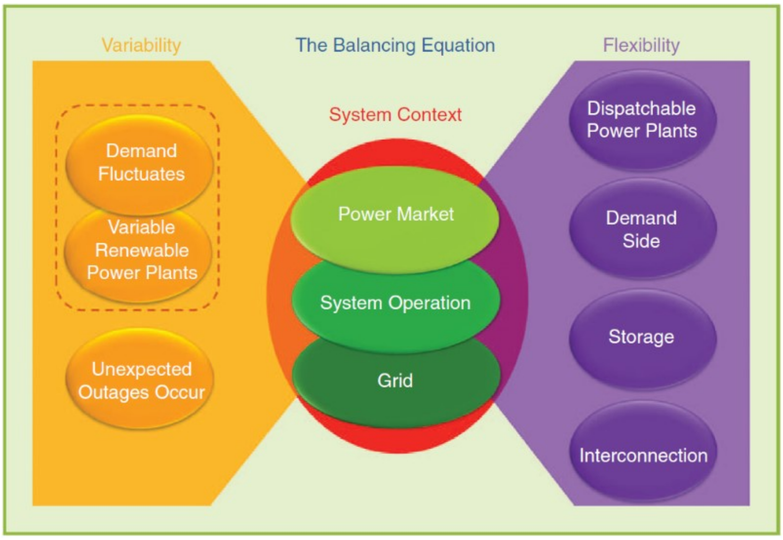

Figure 1: Flexibility needs, sources and enablers (Holttinen et al., 2013)

Options such as storage, grid expansion/interconnection and Demand Response (DR) are able to deal with the increasing intermittency and uncertainty. However, the price-elasticity of electricity demand is not yet sufficient enough to justify storage (Verzijlbergh, Vries, & Lukszo, 2014) and reinforcements of the network require huge investments while the peak loads only occur for a few hours each year (Haque, Nguyen, Vo, & Bliek, 2017).

The other option DR, can be defined as the ability of electricity consumers to change their electricity usage pattern based on signals coming from the power system or electricity market (Ikäheimo, Evens, & Kärkkäinen, 2010). Incorporate Distributed Energy Resources (DERs) with DR to utilize the existing infrastructure more efficiently, and it can be considered an interesting approach to handle the increasing intermittency and uncertainty.

1.2 Aggregators as an intermediary entity

DERs are characterized by their small capacities, and their connection to low and medium voltage electricity distribution grids (Burger, Chaves-Ávila, Batlle, & Pérez-Arriaga, 2017). They need to be aggregated because DERs provide per unit too little capacity and/or energy to be tradable in electricity markets (Eid, Codani, Chen, Perez, & Hakvoort, 2015). Therefore, Aggregators can offer the opportunity to exploit the flexibility potential of small end-users by selling load flexibility benefitting the end-users with rewards or lower energy bills (Carreiro, Jorge, & Antunes, 2017).

In this research, the following definition of an Aggregator, declared by Ikäheimo et al. (2010), is adopted: "*an Aggregator is a company who acts as an intermediary between electricity end-users and DERs owners and the power system participants who wish to serve these end-users or exploit the services provided by these DERs.*"

Eid et al. (2015) reviewed the roles and tasks of an Aggregator in the electricity sector and identified four functions of an Aggregator:

1) Information management

The Aggregator should have insight into the loads of flexibility providers (i.e. the end-users), the size and reliability of services to be provided, and the different prices for different types of flexibility in the market.

2) Bundling of services

The Aggregator uses IT communications and control to activate resources when certain types of flexibility are needed.

3) Matching and market clearing

The Aggregator bids the bundled services on the electricity markets, which could be based on capacity trading like in balancing markets or energy trading like in the Day-Ahead market.

4) Transaction guarantee

The Aggregator is required to provide the Transmission System Operator (TSO) with reliable flexibility offers. Therefore, she manages the risk of actual delivery and provides remuneration (or penalties) to the end-users based on ex-post analysis.

The second function 'bundling of services' is excluded from this study as ICT requirements to successfully implement the role of an aggregator are assumed to be sufficiently available in the near future.

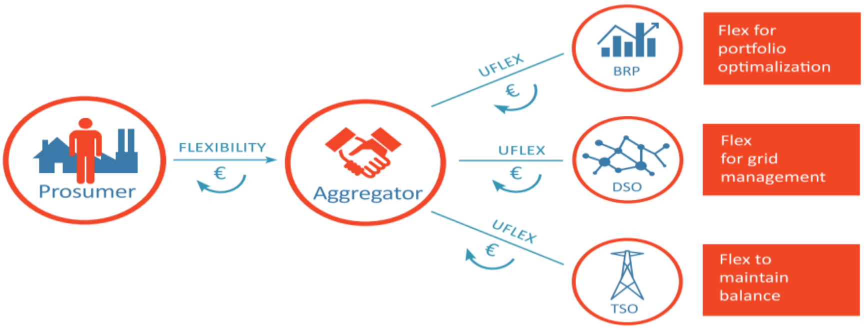

Figure 2: Potential customers for Aggregator's flexibility services (USEF Foundation, 2015)

Figure 2 shows the potential customers for an Aggregator's electric flexibility services. On the one hand, services such as Primary Control Reserve (PCR), Secondary Control Reserve (SCR), and Day-ahead Optimization could be provided by an Aggregator to a Balance Responsible Party (BRP) and the TSO. On the other hand, there is the possibility for Aggregators to add value for Distribution System Operators (DSOs) by providing services contributing to Congestion Management, Voltage Control, and Grid Capacity Management. This study focusses particularly on the services for DSOs, since it is expected that 87% of all Medium-Voltage/Low-Voltage transformers in the Netherlands will be overloaded by the time of 2040 (Veldman, 2013).

1.3 Flex for Congestion Management

Congestion management refers to the responsibility of keeping the line flows in a transmission or distribution system below certain predefined security limits (Veldman, 2013). Jokić (2007) highlighted that efficient congestion management has to adequately transform the predefined security limits of the transmission system into market signals, i.e. electricity prices. The existing markets for PCR and SCR are good examples for managing congestions on the transmission system, but the distribution system lacks such mechanisms to prevent local congestions.

A method to prevent congestion in the distribution networks is power routing (Nguyen, 2010). Power routing deals with the congestions related to the actual load and generation schedules by physically controlling the power flows in distribution networks, for example with the use of DERs (Veldman, 2013). An Aggregator could contribute to this by acting as the intermediary entity between the DERs and the congestion owner (i.e. the DSO), as she is able to connect the services provided by DERs with the power system. A relatively small amount of electrical DERs capacity located downstream from a congestion point can serve a portion of peak demand, such that an upgrade of the transmission and distribution equipment is deferrable (Eyer, 2009; Spiliotis, Ramos Gutierrez, & Belmans, 2016).

Verzijlbergh et al., (2014) studied other methods for managing the congestions in distribution networks that may arise when a large quantity of responsive Electric Vehicle (EV) demand reacts, by means of an intermediary Aggregator, to wholesale electricity prices in a scenario with a large share of vRES. They concluded that an efficient congestion management mechanism will likely be needed for the distribution grid to postpone or even avoid the need for costly network capacity upgrades. The most straightforward method would be advanced capacity allocation in a scenario with one Aggregator, but a capacity auction is also considered a possible solution when more Aggregators are active on the same distribution network. Even so, the design of those mechanisms depend on many factors such as electricity prices, network load, and DERs production profiles.

In sum, increased vRES penetration requires more flexibility that could be provided by DERs located at small end-users combined with DR. Aggregators could act as intermediary entities to exploit the flexibility potential of small end-users and create value for DSOs by delivering electric flexibility services that support, among others, congestion management. In addition to that, congestion management mechanisms will likely be needed to postpone or even avoid the need for costly network upgrades. However, such mechanisms are currently absent in the Dutch power system since the value of an Aggregator's electric flexibility services is not sufficiently understood. The main objective of this research is therefore:

Contribute to the design of congestion management mechanisms in order to reduce the costs of congestion management by providing insight in the value that an Aggregator's electric flexibility services may create for DSOs.

1.4 Case study: Eneco CrowdNett

Eneco CrowdNett is planning to commission a pool of households which will have a combined system of solar-PV and residential Battery Energy Storage (BES) units. Next to optimizing the household's self-consumption, these systems will jointly be able to deliver power to the grid. At initiation, the project will focus to offer PCR capacity, and subsequently SCR capacity on the Dutch balancing markets. Next to that, it could be possible to generate additional income streams via the Day-Ahead market, Intra-day market, or any other markets related to the expected congestion issues in the future.

Eneco CrowdNett can thus be considered as an Aggregator, since she is acting as the intermediary between end-users with a combined system of solar-PV and residential BES units and the power system participants who wish to serve these end-users or exploit the services provided by these DERs. Therefore, the system as designed by Eneco CrowdNett will be used as a case-study during this research.

1.5 Research question

The value that an Aggregator's electric flexibility services may create for the DSOs is still unclear as it depends on many factors. First, there is a strong dependency on the amount and type of assets located in a low-voltage (LV) distribution grid. Second, that same LV distribution grid could have many different configurations in terms of substation capacities and transport cables. Then once value is created, how much value can be captured by whom is also dependent on many exogenous factors such as electricity prices, technological advancements, government policies and regulations.

Therefore, an existing project will be analyzed in order to study those dependencies, and subsequently reflect on this knowledge for other scenarios. The analysis will be applied on the Aggregator CrowdNett, currently in development within the Eneco Group. Nonetheless, the results could be of similar interest to other power system market parties.

This research aims to provide a comprehensive understanding of how the value of an Aggregator's electric flexibility services can be determined for DSOs, without jeopardizing the business case for the Aggregator and the CrowdNett participants themselves. The main research question is therefore as follows:

How can the value of Eneco CrowdNett's electric flexibility services, provided by BES units connected to the LV distribution grid, be determined for DSOs?

This question asks for a methodology rather than a quantitative result. Therefore, a tool that simulates the behavior of residential BES units connected to the LV distribution grid is developed and tested on a specific case, followed by a reflection on its usability for other cases.

1.6 Report Structure

The report is structured as follows. First, the approach and key assumptions applicable on this research are discussed in chapter 2. Thereafter in chapter 3, a system analysis is provided to conceptualize the problem and related systems. Chapter 4 describes the underlying method of the tool and software implementation, followed by the first results in chapter 5 representing an analysis of the end-user's perspective. The subsequent chapter 6 and 7 elaborate on the Aggregator's and DSO perspective respectively. The system perspective discussed in chapter 8 also includes a discussion section that provides some limitations of this study. Finally the conclusions are provided in the last chapter 9, followed by the main contributions and recommendations for further research.

2 Research approach

This chapter describes the steps that will be taken in order to obtain an answer to the main research question (see figure 3). The objective of this research is to get a comprehensive understanding how the value of an Aggregator's electric flexibility services can be determined for DSOs. Thus, before we can determine the value for DSOs, it is important to understand what value can be created by an Aggregator's electric flexibility services in the first place.

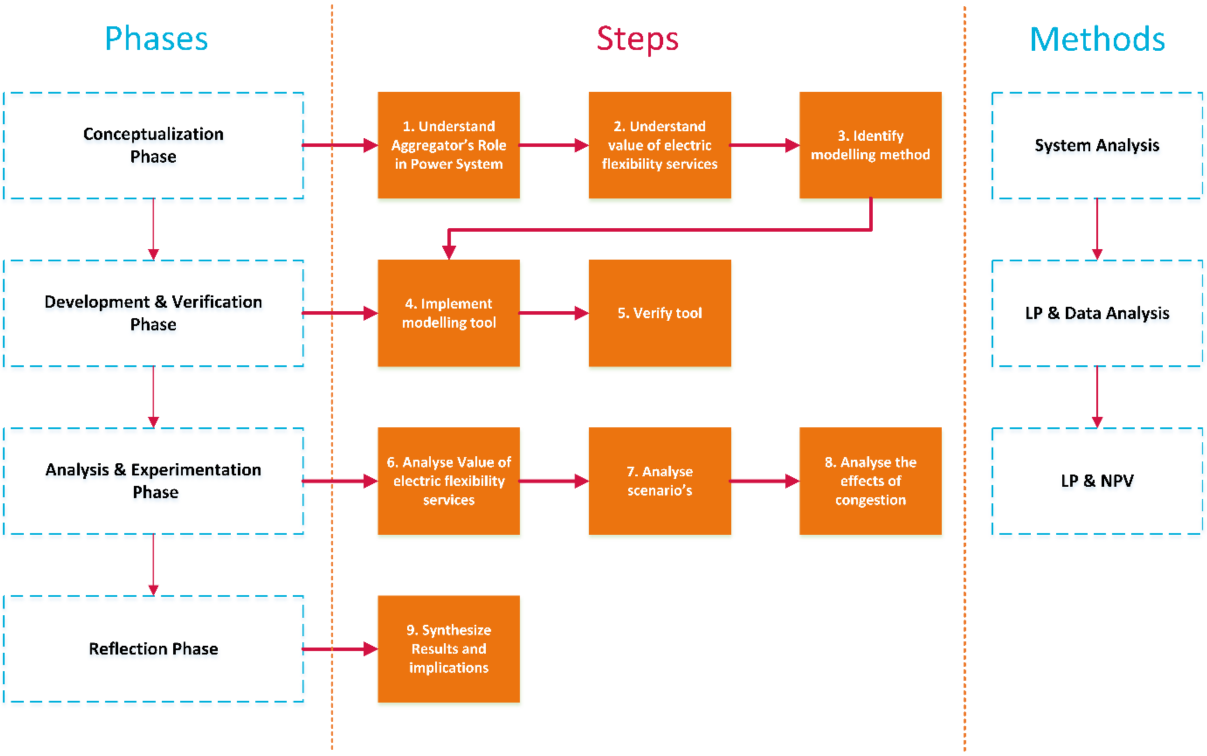

Figure 3: Research Flow Diagram

Conceptualization phase

The first step is to thoroughly understand the role of an Aggregator in the Dutch power system starting with a system analysis to scope the research. Both the physical and institutional components of the Dutch power system will be discussed to define the system boundaries. Then, the role of an Aggregator within that system is conceptualized. The objective of the system analysis is to conceptualize the potential value that could be captured by an Aggregator's electric flexibility services. Therefore, the second step is to understand what an electric flexibility service is and who is able to capture its value. Finally, the insights gained in the first and second step are used to identify a modelling method that will be used to find an answer to the main research question.

Development & verification phase

The objective of the tool that simulates the behavior of BES units is to replicate the system over time. This phase of the research primarily discusses the implementation of the model into the selected software tool and its verification, followed by an analysis of the value from an end-user's perspective.

Analysis & Experimentation Phase

Once the model allows replicating the system over time, it is possible to perform a first assessment on the value of aggregated flexibility services from the end-user's perspective. The assets as present in the case study are used to analyze the benefits that end-users may create by means of the Aggregator.

Subsequently, in the sixth step representing the Aggregator's perspective, the system is assessed according to a so-called "Copper-plate Approach," meaning that electricity flows perfectly within the system and no congestions occur. This is an important assessment, since the DSO is responsible for the operation of the local distribution area, including all activities required to maintain safe, reliable, efficient distribution service to consumers and connected DERs, as well as a stable interface with the transmission grid (Kristov & Martini, 2014). Thus, in theory it should be possible to maximize an Aggregator's electric flexibility services, otherwise opportunity costs are created. The opportunity costs for an Aggregator refer to the revenue increase in energy and balancing markets when no services are allocated to congestion or when no capacity constraints of the distribution network were to exist (Moreno, Moreira, & Strbac, 2015). Therefore, it is in particular studied at what level of DER penetration the business case of the Aggregator becomes jeopardized across various scenarios.

The last step in the analysis & experimentation phase consist of studying the effects of congestion on the value of CrowdNett's electric flexibility representing the DSO's perspective. It is expected that CrowdNett's electric flexibility services are able to support DSOs with congestion management activities. Thus, the value of CrowdNett's electric flexibility services for DSOs can be found in the DSO's willingness to pay for these services.

The DSO's willingness to pay for an Aggregator's electric flexibility services will depend on the DSO's costs with and without those services. Since the DSO's costs, in particular regarding grid reinforcements, occur on a different timescale as the modelled system, it will be required to use another method to assess this value. The Net Present Value (NPV) method is a popular capital budgeting technique that takes into account the time value of money. It shows the difference between the present value of cash inflows, and the present value of cash outflows (i.e. congestion management costs) that occur as a result of undertaking an investment project.

Reflection phase

In the final phase of the research, the results will be synthesized and a discussion of the implications of some of the most important assumptions made during the development of the model will be provided. During this phase of the research, it is clear how the value of CrowdNett's electric flexibility services can be determined for the DSO by using the developed simulation tool. Therefore, an important part of the synthesis will be regarding the economic welfare from a system's perspective. The financial position of each actor is analyzed for two congestion management alternatives, followed by a reflection on the results and the implications for other scenarios.

2.1 Sub-questions

If all steps shown in the research flow diagram are followed accordingly, it will be possible to answer the following sub-questions:

End-user perspective

1. *How much electric flexibility services can be provided by a BES unit connected to the low-voltage distribution grid?*

The available capacity for electric flexibility services strongly depends on the number and type of assets installed in a certain distribution grid. However, this questions refers to the trade-off for each individual BES unit. End-users are able to allow an Aggregator to use a section of their power/energy capacity in return for remuneration. The trade-off is found in comparing the remuneration for offering capacity with the potential benefits gained without offering it.

Aggregator perspective

2. *How many PV-systems can be added to the LV distribution grid without jeopardizing the Aggregator's business case?*

DSO perspective

3. *What are the costs of congestion management services provided by the Aggregator?*

***System** perspective*

4. *To what extent can the Aggregator reduce the total system costs by offering electric flexibility services to the DSO for congestion management?*

The first three sub-questions aim to quantify the value of electric flexibility services from the three different perspectives. The last question number four, aims to combine quantitative analysis with a qualitative analysis in order to enhance the wider practical value of this research.

2.2 Key assumptions

The following key assumptions determine the perspective from which this research is conducted:

- Solar-PV curtailment is not desirable since the resource is free from system cost perspective.
- It is assumed that net-metering policy is subject to change in the future. The remuneration for end-users to feed power into the grid is fixed at the average wholesale price, therewith creating an incentive for local storage.
- ICT requirements to successfully implement the role of an aggregator are sufficiently available.
- All households as present in the case study are assumed to trade their electricity via the Aggregator, who is also the BRP
- Uncertainties in demand and PV production profiles are neglected
- The costs of battery degradation are not studied in detail.
- Retail and PCR prices are fixed at the average of 2016.

3 System analysis

The objective of this chapter is to conceptualize the value that could be captured by an Aggregator's electric flexibility services provided by DERs. First, the concept of electric flexibility services is discussed, followed by a review of the Dutch power system in order to identify the relevant system components and boundaries. Thereafter, the role of an Aggregator within that system is discussed, followed by a description of the possible approaches to assess the potential value of flexibility services from multiple perspectives. The chapter concludes with the model requirements in order to replicate the most important mechanisms of the system.

3.1 The concept of flexibility services

Eid et al., (2016) reviewed how DERs can be used to supply electric flexibility services, which they defined as a ***power adjustment*** sustained at a given ***moment*** for a given ***duration*** from a ***specific location***. Considering this, a flexibility service is characterized by five attributes (see figure 4):

a) Direction: up or down
b) Electrical composition in power capacity
c) Starting time
d) Duration
e) Location

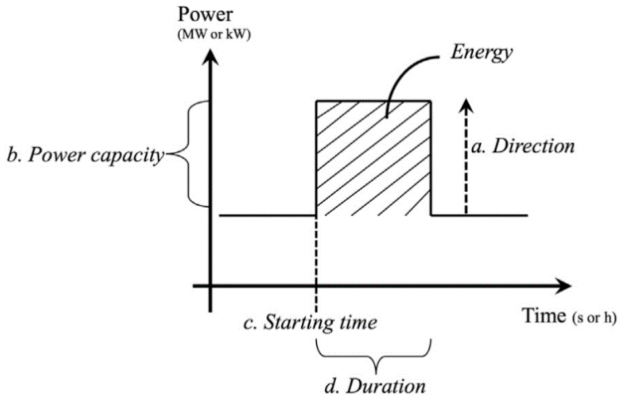

Figure 4: Attributes of an electric flexibility service except for the attribute location (Eid et al., 2016)

Various types of DERs have different implications regarding these characteristics. For example, DERs such as dishwashers and electrical heaters may have a single direction while EVs and storage units have bidirectional capabilities allowing them to act as both consuming and producing units. Using this approach, it is possible to identify the suited DER types for specific technical system flexibility needs (Eid et al., 2016). The system available for the case study (i.e. Eneco CrowdNett) is in theory compatible with all technical system flexibility needs depending amount of aggregated power and energy resources. However, services with long timeframes such as services for seasonal variations are not considered in this study. The particular services that will be considered in this research are discussed in section 3.2.3.

3.2 The Dutch power system

The Dutch power system can be described from a physical and an institutional perspective (see figure 5). Starting with the former, electricity is generated and transported via a High-Voltage (HV) transmission network to smaller Medium-Voltage (MV) and Low-Voltage (LV) distribution networks, where it finds its final use as load for small consumers (typically residential areas) or large consumers (typically industrial areas). The institutional system consists of the regulations, markets and actors facilitating it.

The objective of this section is to identify all relevant system components and boundaries from both a physical and institutional perspective. Section 3.2.1 discusses the transmission network and its physical and institutional context. Similarly, Section 3.2.2 discusses the distribution networks followed by a review of the potential markets that apply for Eneco CrowdNett in section 3.2.3. Finally, concluding remarks will be provided about the relation between the physical and institutional system before moving on towards the role of aggregators within the defined system.

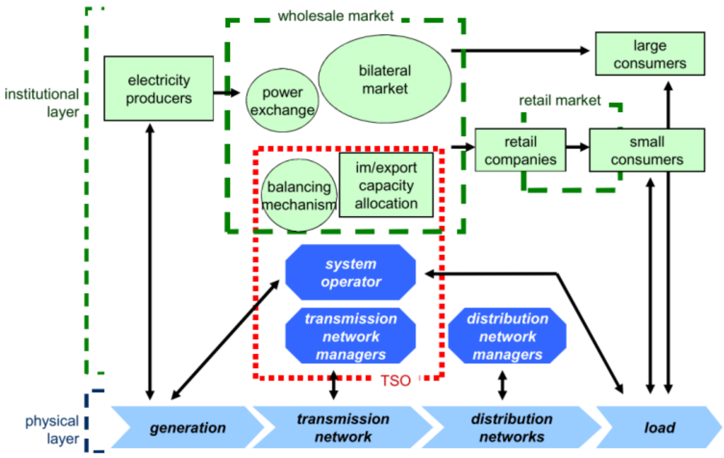

Figure 5: Dutch power system (de Vries et al., 2016)

3.2.1 Transmission Network

TenneT is the Dutch Transmission System Operator (TSO). They are responsible to operate and manage the HV transmission system while aiming to minimize the economic costs of doing so (de Vries et al., 2016). The physical system diagram (see figure 6), provides a representation of the physical assets (i.e. HV transmission lines and substations) that fall under the responsibility of the TSO shown in black. The yellow lines represent the physical assets under the responsibility of the DSO which will be discussed in the next section.

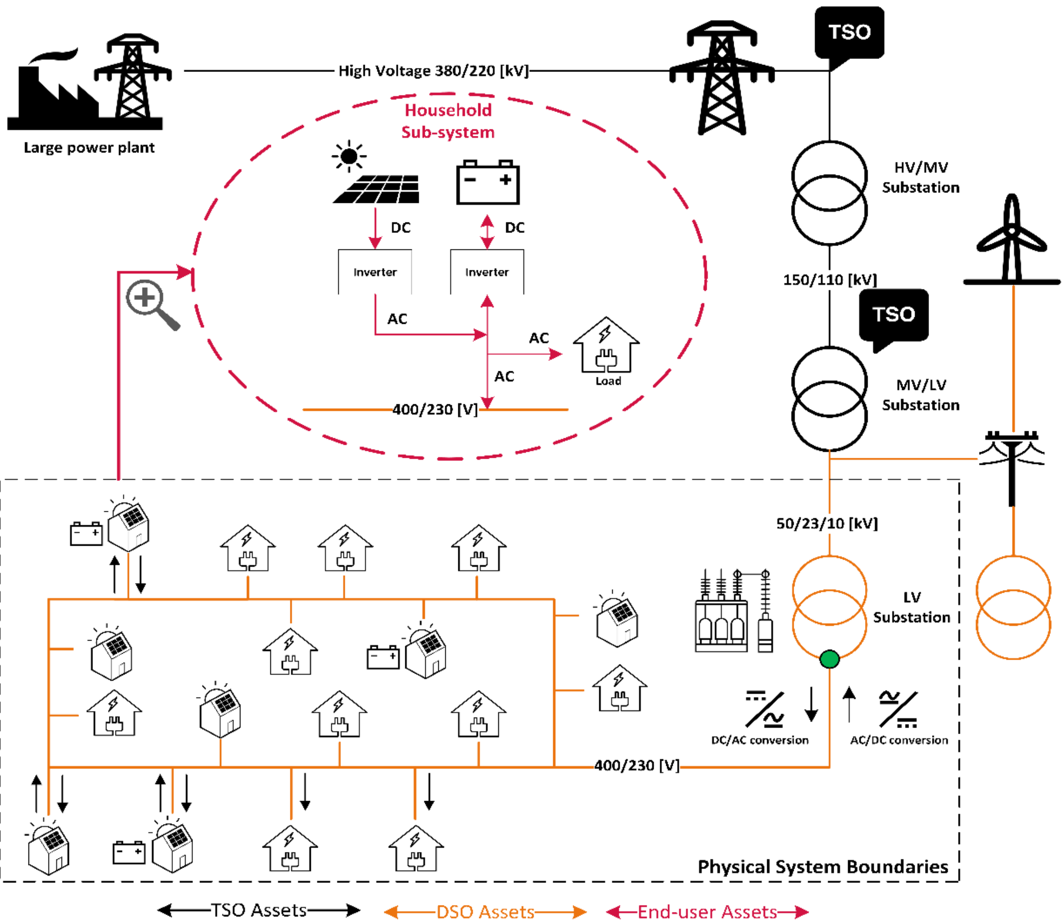

Figure 6: Physical System Diagram

The three most important tasks of the TSO are as follows (de Vries et al., 2016):

1) Balance the injections and withdrawals of power in the transmission network.
2) Manage the network in terms of infrastructure management and operations, including congestion management.
3) Manage import capacity.

In order to ensure the first task, TenneT is able to contract various electric flexibility services on the wholesale market, corresponding to the balancing mechanism shown in figure 5, to maintain real-time balance. These services are traditionally provided by the electricity producers, but the current developments in DERs and DR allow for new methods to balance the grid.

Eneco CrowdNett identified that opportunity and is currently developing the skills and know-how to implement an Aggregator who contracts electric flexibility services. The relevant services for this research are discussed in more detail in section 3.2.3. The balancing mechanism required for the first task of TenneT is considered an important component of the system in this study. The second and third task of TenneT are definitely important factors in changing power systems, but fall outside the scope of this research.

3.2.2 Distribution Networks

This section discusses the responsibilities of DSOs and their related activities: distribution network planning and congestion management. It ends with the physical system boundaries. Distribution networks are mostly owned by independent network companies (i.e. DSOs). The DSO's core responsibility, derived from the EU Third Energy Package legislation (art. 2.6 Electricity Directive 2009/72/EC), is the operation of the local distribution area, including all activities required to maintain safe, reliable, efficient distribution service to consumers and connected DERs, as well as a stable interface with the transmission grid (Kristov & Martini, 2014). Moreover, since all DSOs are owned by local governments, they also have to minimize the economic costs of operating and maintaining the distribution grids (de Vries et al., 2016). Distribution network planning as well as congestion management are considered the most important DSO activities for this research.

3.2.2.1 Distribution network planning

The traditional 'fit-and-forget'[1] approach used in distribution network planning will lead to larger investments in future electricity systems because the network assets need to be prepared for all possible scenarios (SJG Dijkstra and AJ van der Welle, 2012). Utilizing electric flexibility services to support congestion management can save costs compared to applying this fit-and-forget approach, because congestion scenarios can be mitigated by better matching local supply with local demand (Ecorys, 2014).

3.2.2.2 Congestion management

The other important DSO activity, congestion management refers to the responsibility of keeping the line flows in a transmission or distribution system below certain predefined security limits (Veldman, 2013). Referring to the physical system diagram shown in figure 6, congestion can occur at various points within the AC network identified with the yellow lines. However, in order to reduce system complexity, this research focusses on the congestions that occur at the LV substation identified with a green dot in the physical system diagram.

3.2.2.3 Physical system boundaries

Referring back to the core responsibility of DSOs, ensuring efficient distribution service to consumers means being able to supply electricity to end-users. Those end-users on the distribution grids can be both residential end-users and larger industrial end-users. The yellow lines shown in the system diagram (see figure 6) represent the physical assets under the responsibility of the DSOs. The dotted black line defines the physical system boundaries including the sub-systems shown in red under review in this study. The LV substation on the right could for example distribute electricity towards a large industrial end-user, yet this falls outside the scope of this research.

3.2.3 Electricity markets

In the Netherlands, electricity can be traded on five different markets operated by either the APX Group or TenneT. The bulk of electricity is traded on the Day-Ahead market (also referred to as the Spot-market) followed by the Intra-day market, both operated by the APX Group. Even though these markets attempt to equalize supply and demand, there still exists a possibility of imbalances due to power outages or forecasting errors. Therefore, the Primary Control Reserve (PCR) market, Secondary Control Reserve (SCR) market, and the Tertiary Control Reserve (TCR) market, usually referred to as the balancing markets and operated by TenneT, exist to balance supply and demand at all times (Kakorin, Laurisch, & Papaefthymiou, 2015).

---

[1] In a fit-and-forget approach, a network in terms of cables and substations is designed for all possible scenarios during the planning phase, including extreme scenarios.

Due to its scalable characteristics, it is theoretically possible for an Aggregator of DERs to operate on all identified markets as long as a number of technical specifications are met (Eid et al., 2016). However, the Intra-day market is bilateral and therefore contains very sensitive information for competition resulting in the absence of accurate data. Furthermore, the Tertiary Reserve Market (TCR) works with full availability requirements during the entire contract period and is only activated after the PCR and SCR have failed to restore the balance leaving a minimal value to be captured in this market for Aggregators of DERs. Therefore, the markets currently applicable for Eneco CrowdNett (or similar Aggregators) are briefly discussed in the remainder of this section. These are the Day-Ahead market, PCR market, and the SCR market.

3.2.3.1 Day-Ahead market

On the Day-Ahead market, members submit their orders for electricity electronically, after which supply and demand are compared and a market price is established for each hour of the following day. Hourly instruments (single or consecutive) are traded in blocks of 100 [kW] or a multiple thereof, and can have a minimum/maximum price of -500/3000 [€/MWh]. Market members are required to enter into and maintain a BRP contract with TenneT because the hourly instruments are subject to physical delivery of electricity of a constant output on the electricity grid in the Netherlands. It is however possible for a market member to assign a third party as a BRP in order to make nominations on their behalf (APX Group, 2017).

3.2.3.2 Balancing markets

As previously discussed, even though the Day-Ahead market aims to equalize supply and demand there still exist imbalances on the power grid. In order to coordinate the imbalance with interconnected countries, the European Network of Transmission System Operators (ENTSO) sets out load-frequency-control policy to allow TSOs to perform daily operational business. The load-frequency-control system includes different kinds of reserve capacities using the system frequency as a starting point (see figures 7 and 8).

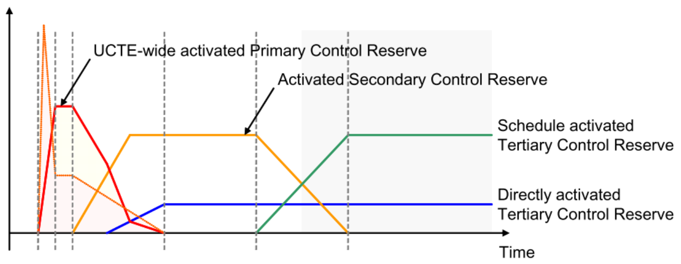

Figure 7: Principle frequency deviation and subsequent activation of reserves (ENTSO-E, 2009)

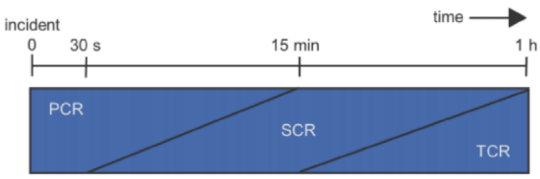

Figure 8: PCR, SCR and TCR with activation times after the incident

3.2.3.3 Primary Control Reserve

The PCR is automatically activated within the entire continental European synchronous control area when the frequency deviates more than +/- 0.02 Hz from the nominal value (Kakorin et al., 2015). In order to meet ENTSO's criteria's, TenneT is obliged to procure a minimum volume of PCR. The minimum primary reserve capacity to be procured in 2015 was 96 [MW] (TenneT, 2017). The minimum bid on the auction for PCR is 1 [MW] and reimbursement of PCR is based on having capacity ready to be activated (i.e. capacity payment), meaning the payment is per [MW] compared to payment per [MWh] as is the case in the Day-Ahead market. PCR is procured by TenneT once per week and the reserve capacity units need be activated by an automated control mechanism.

3.2.3.4 Secondary Control Reserve

SCR is activated after 30 seconds up to 15 minutes after an incident using secondary control reserves and restores the system frequency to the set-point value of 50 Hz. The requirements for secondary reserve units are slightly different compared with primary control reserves. First, the units must be controllable by TenneT's national Frequency Power Regulation. The allowed size of the unit is between 4 [MW] and 200 [MW], it must be adjustable in discrete steps of 1 [MW], the ramp-up and ramp-down speed must be at least 7% per minute in order to achieve full deployment within 15 minutes, and the reaction speed of the unit must be 30 seconds. The SCR is partly covered with yearly contracts and partly traded from one week before delivery until 14:45 on the day before delivery (Klein Entink, 2017). These requirements are not considered applicable for this study since it focusses on LV distribution grids. It would require a large amount of BES units to deliver this service. The SCR market is therefore excluded in the remainder of this study.

3.2.4 Markets and the physical system

The physical and institutional system diagram shown in figure 9, shows how both systems interact with each other. The physical system identified as 'Physical System Boundaries' is shown as the small dashed black box in the left corner within the 'Institutional System Boundaries.' The red arrows represent information flows between the most important actors of the institutional system and positions the role of the Aggregator Eneco CrowdNett within the system. The role of the Aggregator within this system in general and the case-specific actor Eneco CrowdNett will be discussed in more detail in the next section. Most important to note is the dynamic interaction between the Aggregator CrowdNett and a BRP, as well as with the TSO and the DSO.

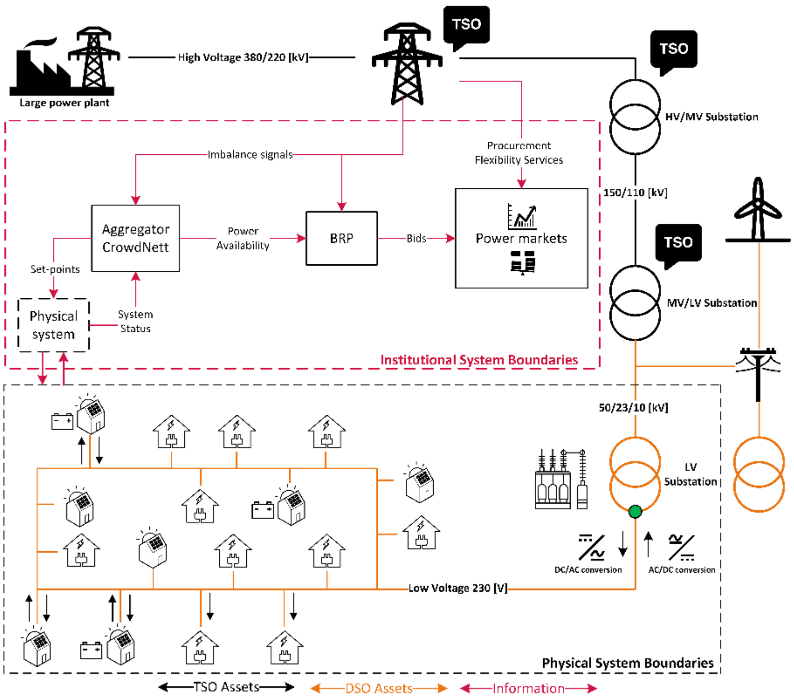

Figure 9: Physical and institutional System diagram

3.3 The role of Aggregators

The objective of this section is to discuss the role of an Aggregator of DERs within the defined physical and institutional system. First, a literature review shows some of the current problems regarding their potential new role and responsibilities within the identified system. Then, Eneco CrowdNett is elaborated on to clarify the case-study that is used within this research. Finally, some concluding remarks will be provided. In particular, these concern the potential value that Aggregators may capture, which will be discussed in section 3.4 in more detail.

3.3.1 Aggregators in the literature

Eid et al. (2015) argued that aggregators can provide potential value for evolving markets, for example in local balancing for distribution grids. However, rules such as minimum bidding values, bid duration and strong penalties for non-supplied services have ensured that few Aggregators have currently entered the market.

In another study, Eid et al. (2016) reviewed the management of existing DERs as flexibility providers and found that the utilization of DERs' flexibility services requires a non-singular approach, due to the fact that each flexibility source has its own technical abilities to provide flexibility services. For example, a combination of tariffs, contracts and direct control should be considered. However, they argued that the role of the Aggregator regardless of its sources of flexibility is still unclear. In particular, they question whether there should be one central Aggregator or multiple Aggregators. Their future research suggestions are to include socio-economic factors such as consumption or production patterns to develop new models for flexibility management.

Carreiro et al. (2017) conducted a large literature study on the topic of Aggregators by analyzing the role of Aggregators in the Smart Grid context in association with DR programs and technologies. The two most important conclusions from that study are as follows. First, attention should be paid to the contracts between end-users, Aggregators and the DSO. It is suggested that bilateral contracts between end-users and the DSO should be established by the Aggregator. A thorough definition of the remuneration scheme, i.e. rewards for load availability and penalties for not complying with load change commitments, is necessary to guarantee implementation. Second, Aggregators should embed adaptive optimization algorithms to compute optimal solutions, in order to satisfy the constraints derived from the interests and preferences of all stakeholders: The DSO, the Aggregator and the end-users.

In sum, Aggregators may capture the potential value offered by flexibility from DERs. However, how much value can be captured and by whom is still unclear. Therefore, a case-study will be performed in order to analyze the value from the perspective of end-users, the Aggregator, and the DSO in a real-life situation. The case-study will be discussed in more detail in the next section.

3.3.2 Eneco CrowdNett as Aggregator

Eneco CrowdNett is planning to commission a pool of households which will have a combined system of solar-PV and residential Battery Energy Storage (BES) units. Next to the household's self-consumption optimization (SCO), these systems will jointly be able to deliver power to the grid. At initiation, the project will focus on offering PCR capacity, and subsequently SCR capacity on the Dutch balancing markets. However, it could be possible to generate additional income streams via the Day-Ahead market, Intra-day market, or other sources related to the expected congestion issues in the future.

Thus, Eneco CrowdNett is acting as an intermediary between end-users and the power system participants who wish to serve these end-users or exploit the services provided by these DERs. Therefore, the system as designed by Eneco CrowdNett will be used as a case-study.

Figure 10 provides the overall system design where Eneco Energy Trade (EET) functions as BRP and Ampard is responsible for the IT structure and actual steering of the BES units identified as H1..HX. Eneco CrowdNett coordinates these activities within the broader Eneco Group, and develops the proposition on the market for end-users.

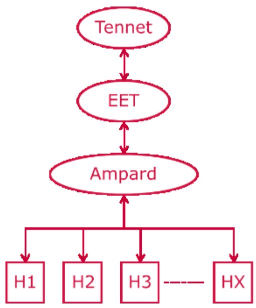

Figure 10: Overall system design Eneco CrowdNett

The physical setup of the system as used for this study has already been shown in the physical system diagram in figure 6. However, some variations on this system may exist. The BES unit used in the current setup is the Tesla Powerwall 2 (PW2), but there will be multiple system variations caused by the size of different solar-PV systems.

Another important variation of the system, which does have an impact on how to operate the system, is the way in which the solar-PV system is connected to the 'in-house AC grid.' A distinction can be made between an AC-coupled and DC-coupled system. In case of a DC-coupled system, the solar-PV and the BES unit are connected to one single inverter, whereas in an AC-coupled system the solar-PV and the BES unit are connected to two separate inverters as shown in figure 11. For practical reasons it is decided to only study the AC-coupled system since most potential end-users have previously installed solar-PV systems with associated inverters before joining Eneco CrowdNett.

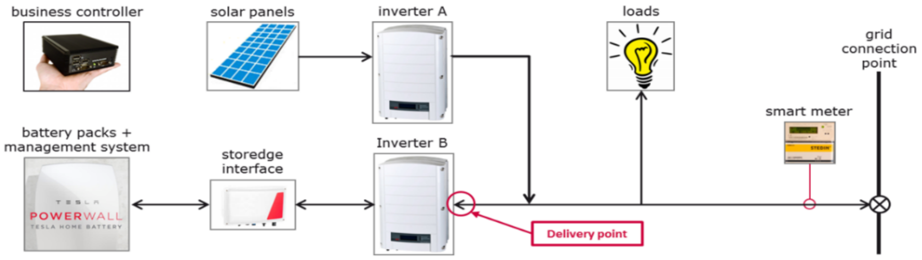

Figure 11: AC-coupled CrowdNett configuration

The AC-coupled system consists of the following hardware:

- Solar-PV system of any type with inverter of any type and size
- BES unit with a name plate capacity of 5 [kW] and 13,5 [kWh]
- The inverter is included in the BES unit with a capacity of 5 [kW]
- Interface system
- Business Controller

At initiation the main application of the system, next to optimizing self-consumption (SCO) will be the PCR market. The maximum delivery to this market with one system will be 4 [kW], where the limitation stems from the power rating (= 5 [kW] / 1,25). Therefore, the storage capacity required for this system would be 2 [kWh], based on 2 x 15 minutes PCR activation, with some additional requirements around the use in normal mode and alert state.

Thus, the system is left with an operational storage bandwidth of 11,5 [kWh] as shown in figure 12. This bandwidth will be used for self-consumption optimization in this study. Under normal circumstances the self-consumption optimization of the battery will maintain the battery in a state of charge within the operational space.

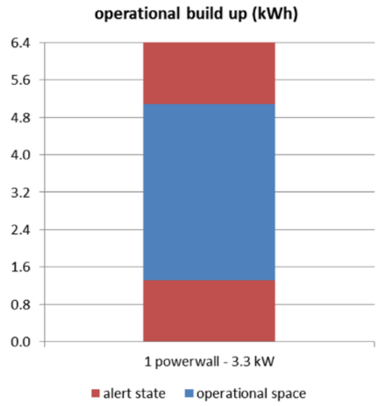

Figure 12: operational bandwidth CrowdNett system

Whether and how much value can be captured by Eneco CrowdNett's system depends on various factors. Probably most important are the number of systems aggregated to offer the electric flexibility services in the first place. Eneco CrowdNett is required to commission and control 250 systems before it will be able to prequalify to deliver 1 [MW] of PCR capacity. Therefore, section 3.4 discusses in more detail the different perspectives on capturing value from an Aggregator's electric flexibility services.

3.4 Capturing the value of flexibility

In the previous sections we discussed the physical and institutional system boundaries as well as the role of an Aggregator within that system from both a literature and case-specific perspective. Burger et al. (2017) reviewed the value of aggregators of DERs in electricity systems and concluded that value can be captured by in different forms, but by whom is regulation, policy and agent dependent.

In order to determine the value of Eneco CrowdNett's electric flexibility services, a distinction is made between the economic welfare of all end-users combined, the Aggregator and the DSO. Economic welfare is defined as the level of prosperity of either an individual or a group of persons (Nordhaus & Samuelson, 2004). It is assumed that the prosperity created by the electricity supply is fixed, implying that a costs reduction is the only way to maximize the economic welfare of each actor.

Whether economic welfare of the whole system, later referred to as system value, is maximized by aggregation of DERs, and how that would be distributed among the identified actors is still unclear. It is expected that load shifting by means of aggregation, from now on referred to as the Aggregator alternative, could reduce the costs of congestion management as compared with the alternative of grid reinforcements. The next three sections therefore define the output indicators, therewith allowing to measure the economic welfare of each actor in both the grid reinforcement as the Aggregator alternative scenario.

3.4.1 The End-user's perspective

The residential end-users are the most important agents in the system since they offer their BES units to an Aggregator. In other words, the whole concept of aggregated electric flexibility services stands or falls depending on the potential gain in economic welfare for the end-users, measured with the self-sufficiency and self-consumption ratio.

The *self-sufficiency* SS_i ratio describes how DERs production can cover the needs of the place where it is installed from a cash-flow perspective as described in (1). The denominator represents the costs of electricity including the benefits gained from storage and feeding in surplus PV power, where the divisor represents the costs without any installed DERs. An increase in this ratio therefore implies a direct benefit for the end-user from an economical perspective.

$$SS_i = \frac{(AEC_i - \sum_{t=1}^{T} P_{i,t}^{Offtake}) \cdot \lambda^{Offtake} + \sum_{t=1}^{T} P_{i,t}^{FeedIn} \cdot \lambda^{FeedIn}}{AEC_i \cdot \pi^{Offtake}} \qquad t \,\forall\, T \tag{1}$$

Where:

$$P_{i,t}^{Offtake} = Electricity\ offtake\ of\ consumer\ i\ during\ period\ t\ in\ [kWh]$$

$$\lambda^{Offtake} = Retail\ price\ of\ electricity\ during\ period\ t\ in\ [€/kWh]$$

$$P_{i,t}^{FeedIn} = Electricity\ FeedIn\ of\ consumer\ during\ period\ t\ in\ [kWh]$$

$$\lambda^{FeedIn} = FeedIn\ price\ of\ electricity\ during\ period\ t\ in\ [€/kWh]$$

$$AEC_i = Annual\ Electricity\ Consumption\ of\ consumer\ i\ in\ [kWh]$$

It should not be confused with the *self-consumption* ratio SC_i, which describes the local utilization of PV electricity from an energy perspective (Masson, Pvps, Briano, Jesus, & Creara, 2016) according to (2).

$$SC_i = \frac{AEC_i - \sum_{t=1}^{T} P_{i,t}^{Offtake}}{\sum_{t=1}^{T} P_{i,t}^{PV}} \qquad t \,\forall\, T \tag{2}$$

Where:

$$P_{i,t}^{PV} = Electricity\ Produced\ by\ the\ PVsystem\ of\ Enduser\ i\ during\ period\ t\ in\ [kWh]$$

Thus, an increase in this ratio does not imply any economic benefit. End-users might however value this ratio in the context of sustainability. For example, via the contribution end-users would make when they utilize their own zero-carbon PV-system production more efficiently and therewith become less dependent on the electricity grid.

In sum, the most straightforward way to increase economic welfare for end-users is found in lowering their costs of electricity, therewith improving their self-sufficiency ratio. This is however strongly dependent on the current applicable support scheme called net-metering, which is discussed in more detail in the next section.

3.4.1.1 Net-metering policy

Net-metering applies to consumers, who are at the same time producer of electricity, and are connected to the electricity grid through a connection with a throughput value smaller than or equal to 3x80 Ampere. It allows them to inject their surplus electricity in the grid and therewith lower their electricity bought from the retail company on a yearly basis (ConsuWijzer ACM, n.d.). Consequently, an increase in the self-sufficiency ratio for an end-user by storing electricity in a BES unit is not possible because retail companies use fixed electricity prices within their contracts.

In other words, there is no incentive for local storage because under current regulations and fixed retail electricity prices, the grid functions as a large BES unit. Nonetheless, it is expected that in the future this policy will be adjusted in favor of incentivizing the use of residential BES units. Therefore in the remainder of this study, it is assumed that the future support scheme will allow end-users with PV to sell their surplus electricity against a different price than the offtake price, therewith intrinsically creating an incentive for local electricity storage.

3.4.1.2 Selling Load Flexibility

Besides an increased SS and SC ratio, end-users could also increase their economic welfare by selling load flexibility to the Aggregator. Eneco CrowdNett rewards the end-users with a yearly premium for allowing her to use their DERs on the wholesale markets. The total economic welfare for all end-users combined is therefore not only dependent on the costs of electricity, but also include the additional benefit gained by offering load flexibility.

Equation (3) operationalizes the economic welfare of all end-users combined by calculating the costs of electricity between the brackets for each end-user i while also incorporating the yearly premium $\pi^{FlexPremium}$ (outside the brackets). The costs of additional network tariffs C_i^{Grid} represent the costs of congestion management that the DSO passes on to the end-users.

$$W^{Endusers} = \sum_{t=1}^{T}\sum_{i}^{n}\left((P_{i,t}^{FeedIn} - P_i^{Curtail}) \cdot \lambda^{FeedIn} - P_{i,t}^{Offtake} \cdot \lambda^{Offtake} -\right) + n^B \cdot \lambda^{FlexPremium} - C_i^{Grid} \quad t \forall T \tag{3}$$

Where:

$$W^{Endusers} = Economic\ welfare\ for\ all\ endusers\ i\ active\ in\ the\ system\ in\ [€/year]$$

$$P_i^{Curtail} = Electricity\ curtailed\ in\ [kWh]$$

$$\lambda^{FlexPremium} = The\ premium\ provided\ by\ the\ Aggregator\ in\ [€/year]$$

$$n^B = number\ of\ consumers\ with\ a\ BES\ unit\ [\#]$$

$$C_i^{Grid} = Costs\ of\ additional\ network\ tariffs\ [€/year]$$

It is important to note that the discussed indicator represents a theoretical maximum under the assumed electricity and premium prices. Whether and how much value is actually captured by end-users depends on market dynamics such as pricing rules, wholesale price developments, and negotiations.

3.4.1.3 Investment in the BES unit

Note that (3) does not consider the investment costs in the BES unit by the end-user, but rather shows the welfare on a yearly basis. The NPV-method can be used in a similar matter to determine whether investing in the BES unit is sufficiently viable for an end-user according (4), provided that the initial investment costs C_0, required discount rate r, depreciation time t are available.

$$NPV_i = \sum_{t=1}^{T}\frac{C_{i,t}^{Enduser}}{(1+r)^t} - C_0 \tag{4}$$

Where $C_{i,t}^{Enduser}$ is defined as the difference between the yearly costs of electricity with and without a BES unit as shown in (5):

$$C_{i,t}^{Enduser} = AEC_i \cdot \lambda^{Offtake} - \sum_{t=1}^{T}\left(P_{i,t}^{Offtake} \cdot \lambda^{Offtake} - P_{i,t}^{FeedIn} \cdot \lambda^{FeedIn} - n^B \cdot \lambda^{FlexPremium}\right) \quad t \forall T \tag{5}$$

3.4.2 The Aggregator's perspective

The role of Aggregators and their centralized control over DERs is equally as important as the end-users making them available. In the remainder of this section, the economic welfare of the Aggregator is defined.

3.4.2.1 The Aggregator's economic welfare

The economic welfare of the Aggregator mostly depends on the amount of power capacity that can be reserved at the end-user's assets to be utilized on the wholesale markets. There is also an opportunity to reduce the total costs of supplied electricity from a BRP perspective through utilizing the BES units for energy arbitrage. However, due to the small price difference on the APX market and low expected yields for storage options, it is considered outside the scope of this research (Vegte, Melzen, & Spek, 2016). Intraday trading might also be an option due to a higher volatility, but also falls outside the scope of this research due to the lack of sufficient data.

In this research, the Aggregator's economic welfare is therefore measured according to (6). The first five terms in (6) represent the revenues and costs of selling power to end-users corrected by the applicable taxes, whereas the remaining terms (on the right of the first plus sign) represent the revenues and costs related to the PCR market and congestion management services. The cost of operating the system in terms of control are assumed negligible. The remuneration for PCR services is based on a capacity payment per week as previously discussed in the system analysis.

$$W^{Agg} = \sum_{t=1}^{T}\sum_{i}^{n}\left(P_{i,t}^{Offtake}\cdot(\lambda^{Offtake}-\lambda^{Tax})-P_{i,t}^{FeedIn}\cdot\lambda^{FeedIn}\right)+n^{B}\cdot\left(R^{PCR}-\lambda^{FlexPremium}\right) + TR^{Congestion} \qquad t\,\forall\,T \tag{6}$$

Where:

$$W^{Agg} = Economic\ welfare\ of\ the\ Aggregator\ in\ [€/year]$$
$$\lambda^{Tax} = \text{Power}\ taxes\ received\ from\ endusers\ in\ [€/\text{kWh}]$$
$$R^{PCR} = Revenue\ per\ BES\ unit\ in\ the\ PCR\ market\ in\ [€/year]$$
$$TR^{Congestion} = Total\ revenue\ through\ congestion\ management\ services\ in\ [€/year]$$

The Aggregator's economic welfare indicator represents the theoretical maximum profit to be realized with the assumed electricity prices, after the taxes and network tariffs that apply on end-users are paid to the appropriate parties. Note that the taxes being collected by the government leave the system, while grid tariffs remain in the system since they are exchanged between the end-users and the DSO.

3.4.2.2 PCR market revenues

In the remainder of this study it is assumed that the Aggregator CrowdNett has 1 [MW] of power available for PCR services via 250 BES units based on the maximum setup of 4 [kW/system]. The remuneration for PCR services is based on the pay-as-bid method. Therefore, figure 13 shows the historical average bids for PCR services from the beginning of 2015 until the end of 2017. It is based on data obtained from regelleistung.net, the online data platform where TenneT publishes the tender results of PCR services.

In order to calculate the Aggregator's economic welfare as shown in (6), it is decided to select an average value for PCR services based on the data from 2016 and 2017. The values of 2015 are excluded from the average since the average bids in 2016 and 2017 have clearly decreased compared with 2015. On average, the value for PCR services has been 2500 [€/MW/week], corresponding to a revenue of R^{PCR} of 520 [€/year/BES unit].

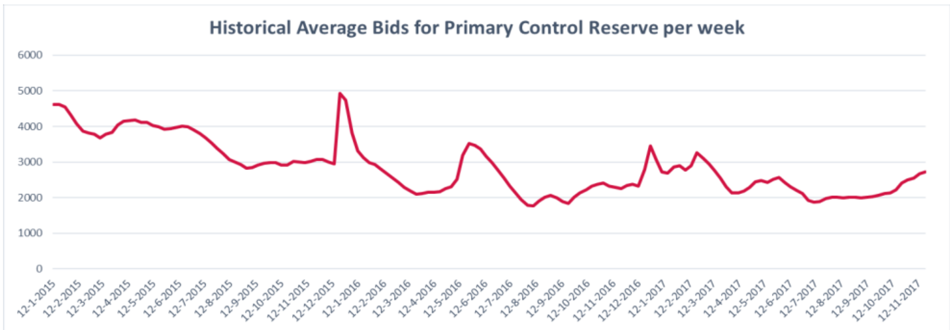

Figure 13: Average bids for PCR from Jan 2015 - Nov 2017

3.4.3 The DSO's perspective

Lastly, the system considered in this study is the LV distribution grid owned and operated by local DSOs. Since DSOs are public parties, they are by regulation not allowed to participate in activities to increase their economic welfare in terms of additional profits. A cost reduction for DSOs is therefore considered an increase in economic welfare.

Although, aggregators have the possibility to supply a broad spectrum of services for the DSO (USEF Foundation, 2015), this study focusses in particular on the possibility to provide load shifting services to avoid congestions at the substation level. The most important output indicator to measure the economic welfare for the DSO is therefore the costs of grid reinforcements which can be calculated using the Net Present Value (NPV) method in (7).

$$NPV = \sum_{t=1}^{T} \frac{C_t^{DSO}}{(1+r)^t} - C_0 \tag{7}$$

Where:

$$C_t^{DSO} = Net\ cash\ flow\ during\ period\ t\ in\ [€]$$

$$C_0 = Total\ initial\ investment\ costs\ in\ [€]$$

$$r = discount\ rate$$

$$t = number\ of\ time\ periods\ in\ [years]$$

Provided that the initial investment costs, required discount rate, and depreciation time are given, C_t^{DSO} can be calculated to determine net cash flow of grid reinforcements by solving the equation for a positive NPV. Subsequently, they can be compared with the costs of load shifting over an equal timeframe to select the most efficient alternative. It is assumed that the costs of congestion management are passed on to the end-users in the grid regardless of the alternative. The cheapest alternative therefore corresponds to the most efficient one for the system.

Whether the DSO needs congestion management in the first place depends on the expected congestions in the grid. Therefore, the following additional output indicators are defined to assess when, and to what extent, congestions are expected to occur in the LV distribution grid.

The Frequency of Sub-station Overload FSO_w is shown in (8), where w refers to the weeks in a year. It calculates the frequency of PTUs x_t shown in (9) where the power flow at the substation reaches or exceeds its maximum capacity $P^{Substation,max}$ for each week of the year.

$$FSO_w = \sum_{t=672(w-1)+1}^{672w} x_t \tag{8}$$

$$x_t = \begin{cases} 1\ if\ P_t^{Substation,flow} \geq P^{Substation,max} \\ 0 \qquad\qquad\qquad\qquad\qquad if\ otherwise \end{cases} \tag{9}$$

Where:

$$P_t^{Substation,flow} = The\ power\ flow\ at\ the\ LV\ Substation\ during\ period\ t\ in\ [kW]$$

$$P^{Substation,max} = Maximum\ power\ capacity\ of\ the\ LV\ Substation\ in\ [kW]$$

In the end, the costs for the DSO depend on the selected alternative to avoid congestions in the distribution grid. On the one hand, there is the possibility to reinforce the grid by investing in new assets, from now on referred to as the 'grid reinforcement alternative'. Such investments are usually not considered very efficient since the transformer capacity has to be doubled even when the power flows only slightly exceed $P^{Substation,max}$.

The Aggregator could on the other hand potentially offer a cheaper solution by withdrawing power/energy capacity from PCR and use it for load shifting services. Although the FSO_w provides valuable insight in the magnitude of the congestion problem, insight in the recurrence of weeks $FSO^{TotalWeeks}$ that face any congestion issues at all, is even more important to study the congestions as shown in (10) and (11).

$$FSO^{TotalWeeks} = \sum_{w=1}^{52} y_w \tag{10}$$

$$y_w = \begin{cases} 1 \; if \; FSO_w \geq 1 \\ 0 \; if \; otherwise \end{cases} \tag{11}$$

Lastly, the economic welfare for DSOs is determined according to (12). Both the $TR^{Tariffs}$ and $TC^{Congestion}$ for the DSO refer to additional revenues and costs for the studied LV distribution grid. All other costs and revenues related to other grids are therefore neglected.

$$W^{DSO} = TR^{Tariffs} - TC^{Congestion} \tag{12}$$

Where:

$$TR^{Tariffs} = \; Total\; Revenues\; through\; additional\; Grid\; Tariffs\; [€/year]$$

$$TC^{Congestion} = \; Total\; Costs\; of\; additional\; Congestion\; Management\; [€/year]$$

3.4.4 System value

In the previous three sections we discussed the economic welfare indicators for each identified actor in the system. This subsequently allows determining the economic welfare of the system as a whole according to (13), also referred to as system value.

$$W^{System} = W^{DSO} + W^{Endusers} + W^{Agg} \tag{13}$$

An increase in W^{System} does however not automatically mean that the benefits are distributed equally. The Aggregator might for example capture all the benefits at the expense of the end-users. In the remainder of this study it is aimed for to provide insight in the dynamics between the actors in the system of the identified case study. The next section therefore discusses the model requirements to replicate such system dynamics over time, with in particular the inclusion of residential BES units operated by an aggregator.

3.5 Model requirements

The system analysis as provided in section 3 discussed the concept of a flexibility service, reviewed the Dutch power system and the role of an Aggregator within it, identified the physical and institutional system boundaries, and conceptualized the value of flexibility by distinguishing between economic welfare per actor and the whole system. Thus, now that we understand how DERs located in the LV distribution grid can provide electric flexibility services by means of an Aggregator, the next step is to identify the model requirements in order to provide insight in the trade-off between avoiding grid reinforcement costs for the DSO and the costs of the Aggregator alternative. First, the core principles/mechanisms of the system that have a significant impact on the economic welfare indicators are reviewed from both a technical and institutional perspective, followed by the identified model requirements.

The core mechanism of the system from a technical perspective is found in the interaction of the identified sub-system (household) with the larger system (LV distribution grid) as shown in the system diagram (see figure 6). Whether and how much electricity is exchanged between those systems in terms of power and energy, ultimately determines the economic welfare for each identified actor. Most relevant for this study is the possibility for DSOs to avoid grid reinforcement costs when utilizing load shifting services offered by an Aggregator. The technical components/concepts within the system that have the largest impact on the welfare indicators are therefore the residential BES units operated the Aggregator, the PV-systems, the residential demands and the LV substation.

From an institutional system perspective, it can be concluded that the core mechanism is found in the interaction between the Aggregator and the wholesale markets. The Aggregator's welfare is the direct result of the selected market to utilize the aggregated BES units, which are day-ahead and PCR market in this study. None of the interactions between end-users and the wholesale markets would exist without the intermediary aggregator.

To sum this up, it is expected that an Aggregator could increase the value in the system (i.e. reduce system costs), if the BES units are optimally dispatched according to the available PV production and residential demands. Whether each actor could capture an equal share of additional system value is however still unclear.

The following key model requirements are derived from the above in order to select a method to simulate the BES units operated by an Aggregator over time. The model should:

1) Allow to include exogenous parameters for each Power Time Unit (PTU)
    a. Electricity prices
    b. Residential demand profiles
    c. PV-system production profiles
    d. BES Unit parameters
2) Include interaction of end-users with the other system components
    a. The local AC distribution grid
    b. LV substation
3) Determine the active power flows for each PTU based on lowest costs at the residential level considering the household configuration, and calculate corresponding cash-flows.
4) Determine the optimal dispatch of the residential BES Unit based on lowest total system costs or maximum profits.
5) Allow the aggregator to forecast each of the exogenous parameters up to one full day (=96 PTUs) in advance

For each identified exogenous variable there is data available with a resolution of one PTU (15 minutes). However, the activation of PCR services occurs on a second to second basis since the available capacity is responding to the frequency of the grid via an automated control mechanism. Including such a mechanism would complicate the model without gaining any significant new insights. Therefore, it is decided to exclude the balancing mechanism from the model, but instead use the historical probability distribution of PCR activation (i.e. frequency deviation data) to analyze the expected impact of PCR availability on the LV substation.

4 Methodology

The objective of this chapter is to identify a method and develop a tool that simulates the behavior of BES units on a LV distribution grid to study the value of an Aggregator's electric flexibility services over time. First, the type of problem is reviewed. Then, potential methods are discussed followed by selecting the most useful method for this study based on the characteristics of the problem. Thereafter, the model structure is discussed in terms of the mathematical relations, and the network configuration. The chapter concludes with a description of and reflection on the software implementation.

4.1 Unit Commitment Problem

Based on section 3.5, in particular the fourth modelling requirement, it can be concluded that the problem at hand can be framed as an Unit Commitment Problem (UCP) as discussed by Frangioni, Lacalandra, & van Ackooij (2015). They highlight that: "The Unit Commitment Problem (deterministic or uncertain) requires to minimize the cost, or maximize the benefit, obtained by the production schedule for the available generating units over a given time horizon."

Techniques commonly used to solve UCPs are found in the field of mathematical optimization, with Linear Programming (LP), Mixed Integer Linear Programming (MILP), and Quadratic Programming (QP) being the most popular ones. The LP technique allows for finding the optimal outcome of a certain objective function by varying decision variables in a set of continuous linear equations that are bound by a set of constraints. MILP techniques are very similar to LP, but allow for calculating certain variables as integers while other variables can vary over a continuous range of values. This can be useful in particular for modelling the on/off state of assets in a system. QP techniques allow for additional complexity by incorporating a quadratic objective function.

In this research, the generation units of the UCP are represented by CrowdNett's residential BES units that primarily deliver local services, but can also deliver congestion management services through load shifting. The local Self-Consumption Optimization (SCO) service allows end-users to store their surplus PV electricity for other moments in time. The BES units either charge or discharge based on the local conditions in the in-house grid. Similarly, load shifting services ensure that BES units charge or discharge extra power according to the congestions in the grid.

By doing so, the system would aim to minimize the total costs, since end-users return their investment back by increasing their self-sufficiency through SCO, and DSOs are obliged to minimize the costs of congestion management. Solving the UCP therefore requires the inclusion of prices determining the total costs of the system, namely prices for extracting power from and feeding in surplus power to the grid. The amount of power extracted from and fed into the grid, the charging and discharging behavior, and a possibility to curtail PV power therefore together form the degrees of freedom that eventually determine the total costs of the system.

Nonetheless, merely minimizing the costs of the system over time would only provide the static behavior of the BES units given the time horizon established by the input data, and based on perfect information regarding the entire dataset. Therefore, a rolling time horizon is required to study the system's behavior as a result of the dynamic behavior between the actors over time. As such, the BES units are provided with perfect knowledge for a limited period representing a more realistic system. The concept of a rolling time horizon is visualized in figure 14 where *p* stands for previous optimization period, *c* for current optimization period, *n* for length of optimization period, and *l* for look-ahead period. It shows that the current period *c* is optimized based on the information of that whole period plus information of an additionally defined look-ahead period *l*. The corresponding parameterization is discussed in section 4.3.3. Note that *l* and *1* appear very similar optically in figure 14, but do have different meanings.

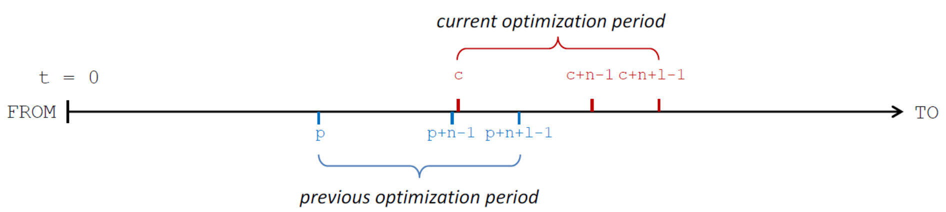

Figure 14: Optimization periods in Linny-R solver (Bots, cited in Hylkema 2017)

Based on the content of this section, it can be concluded that the minimum requirement to select a solving method for the UCP is the ability to model the processes representing the identified services SCO and load shifting. None of those processes (i.e. decision variables) have threshold parameters. Therefore, they can be described as a set of linear equations and constraints over a continuous range of values. That means that Linear Programming (LP) is considered a useful method to solve the UCP.

Figure 15 presents a visualization of the relation between the input data, UCP model, decision variables, and the output indicators. Note that the decision variables are generated as output of the UCP model in the form of raw data, after which it is processed together with the expected PCR activation into the output indicators to analyze the different perspectives.

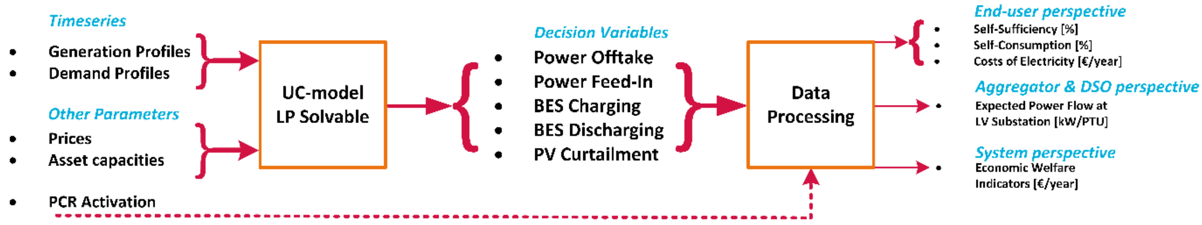

Figure 15: UCP input output diagram

4.2 LP Model Structure

The next step in solving the UCP with LP is to translate the core model mechanisms into an objective function subject to its constraints, and define the degrees of freedom in terms of the decision variables. For modelling the Aggregator on the LV distribution grid with an LP approach, the objective function would aim to minimize the total costs of electricity C^{Total} while satisfying local power demand according to the available PV-system and BES units, and with the possibility to extract power from and feeding power into the grid. Equation (14) shows the objective function, in which t is considered one PTU of 15 minutes. Note that $P_{i,t}^{Offtake}$ and $P_{i,t}^{FeedIn}$ represent the first two decision variables.

$$MIN : C^{Total}$$

$$C^{Total} = \sum_{t=1}^{T}\left(\sum_{i}^{n} P_{i,t}^{Offtake} * \lambda^{Offtake} - P_{i,t}^{FeedIn} * \lambda^{FeedIn}\right) \tag{14}$$

Where:

$$C^{Total} = Total\ costs\ of\ electricity\ in\ the\ LV\ distribution\ grid\ in\ [€/year]$$

Satisfying local power demand is ensured via (15). This represents the power balance of the system, including the efficiency losses caused by the inverters. Note that a third decision variable $P_t^{Curtail}$ is added to the demand side of the equation allowing the system to curtail PV-system power whenever considered necessary. The system would however avoid curtailment, since no price is assigned to this process. Hence, curtailment would only occur when both the BES unit is fully charged, and the feed-in process is blocked due to the constrained connection capacity as showed in (20). Also note that in this model, the BES unit can only be charged via the PV-system, where in reality it is possible to charge from the grid as well.

$$P_t^{Offtake} + P_t^{PV} \cdot \eta^{PV} - P_t^{FeedIn} - P_t^{C} \cdot \eta^{B} \cdot \eta^{PV} + P_t^{D} \cdot \eta^{B} = P_t^{Demand} + P_t^{Curtail} \tag{15}$$

Where:

$$\eta^{PV} = Inverter\ efficiency\ of\ the\ PV\ system\ in\ [\%]$$
$$\eta^{B} = Inverter\ efficiency\ of\ the\ BES\ Unit\ in\ [\%]$$
$$P_t^{C} = Power\ charged\ into\ the\ BES\ Unit\ originating\ from\ the\ PV\ system\ in\ [kWh]$$
$$P_t^{D} = Power\ discharged\ from\ the\ BES\ Unit\ to\ supply\ local\ demand\ in\ [kWh]$$
$$P_t^{Curtail} = Power\ curtailed\ from\ the\ PV\ system\ in\ [kWh]$$

The state of the BES unit E_t^B and its charging and discharging behavior are given by (16-19). They describe the in- and outflow of electricity in [kWh] according to the maximum power capacity of the BES unit's inverter in [kWh/PTU]. Note that the power capacities are provided in [kWh/PTU] instead of the usual [kW] due to the characteristics of the selected software tool. Moreover, note that the variables P_t^C and P_t^D represent the final two decision variables.

$$E_t^B = E_{t-1}^B + P_t^C \cdot \eta^B \cdot \eta^{PV} - P_t^D \cdot \eta^B - P_t^{Losses} \tag{16}$$

$$0 \leq E_t^B \leq E^{B,Max} \tag{17}$$

$$P_t^C \leq P^{B,Max} \tag{18}$$

$$P_t^D \leq P^{B,Max} \tag{19}$$

Where:

$$P_t^{Losses} = Fixed\ SelfDischarge\ Losses\ in\ [kWh]$$
$$E^{B,Max} = Maximum\ Energy\ Capacity\ of\ BES\ Unit\ in\ [kWh]$$
$$P^{B,Max} = Maximum\ Power\ Capacity\ of\ BES\ Unit\ in\ [kWh/PTU]$$

The equations (14-19) ensure that end-users are able to satisfy their local demand by extracting power from their PV-system, BES unit, and the grid if necessary - all at minimal costs. The last and final equation (20) assures that the maximum capacity of the network is taken into account. The parameter $P^{Connection,Max}$ could represent both the connection capacity of the household as well as the LV substation on the grid level depending on the parameterization.

$$P_t^{FeedIn} + P_t^{Offtake} \leq P^{Connection,Max} \tag{20}$$

Where:

$$P^{Connection,Max} = Maximum\ Power\ Capacity\ of\ LV\ Substation\ in\ [kWh/PTU]$$

4.3 Network configuration

The previous section showed how the most important model mechanisms can be translated into linear equations such that they can be implemented in the software. However, the configuration of the network is still to be discussed. It is important to select a grid configuration that is representative for The Netherlands in order to ensure a wider applicability of this research. Therefore, the HERMES DG 3 project is consulted.

The HERMES DG 3 project in collaboration with DSOs, identified the most representative LV distribution grids used in residential areas in The Netherlands based on the following three step approach (Lumig & Locht, 2009). They:

1) Identified the most occurring type of households based on year of construction, surface, and insulation.
2) Selected the most occurring type of neighborhoods based on the living environments used by the old Dutch Ministry of Housing and Spatial Planning.
3) Selected an existing Dutch LV-grid for each of the relevant type of neighborhoods.

In the second phase of the HERMES DG 3 project, simulations were conducted based on the actual LV-grid configurations that were supplied by the DSOs. Both the voltage and load behavior of the grids were simulated in various scenarios that incorporated heat pumps, EVs, PV-systems, and micro combined heat and power (micro-CHP) systems. Note that in none of their scenarios they considered the penetration of any electrical energy storage devices, which is the focus of this research.

The LV grid to be studied in this research should at least allow for the increased penetration of DERs in the future, with PV-systems and BES units in particular. Therefore, the most occurring type of households in the neighborhood should rather consist of (semi-)detached houses instead of porch flats. The living environment “green urban” particularly possesses these features being spaciously designed, and considered very representative for the somewhat older neighborhoods (Lumig & Uytterhoeven, 2009).

The neighborhood of Kijkduin just outside of The Hague is selected as the LV grid to represent the green urban living environment. It consists primarily of large detached houses connected to 4*95 [mm^2] and 4*50 [mm^2] copper cables fed through a substation of 200 [kVA]. The total number of connections to the substation is 111. The following to figures 16 and 17 show the location and the meshed network structure of the LV grid in Kijkduin.

Figure 16: Location of Kijkduin (source: Google Maps)

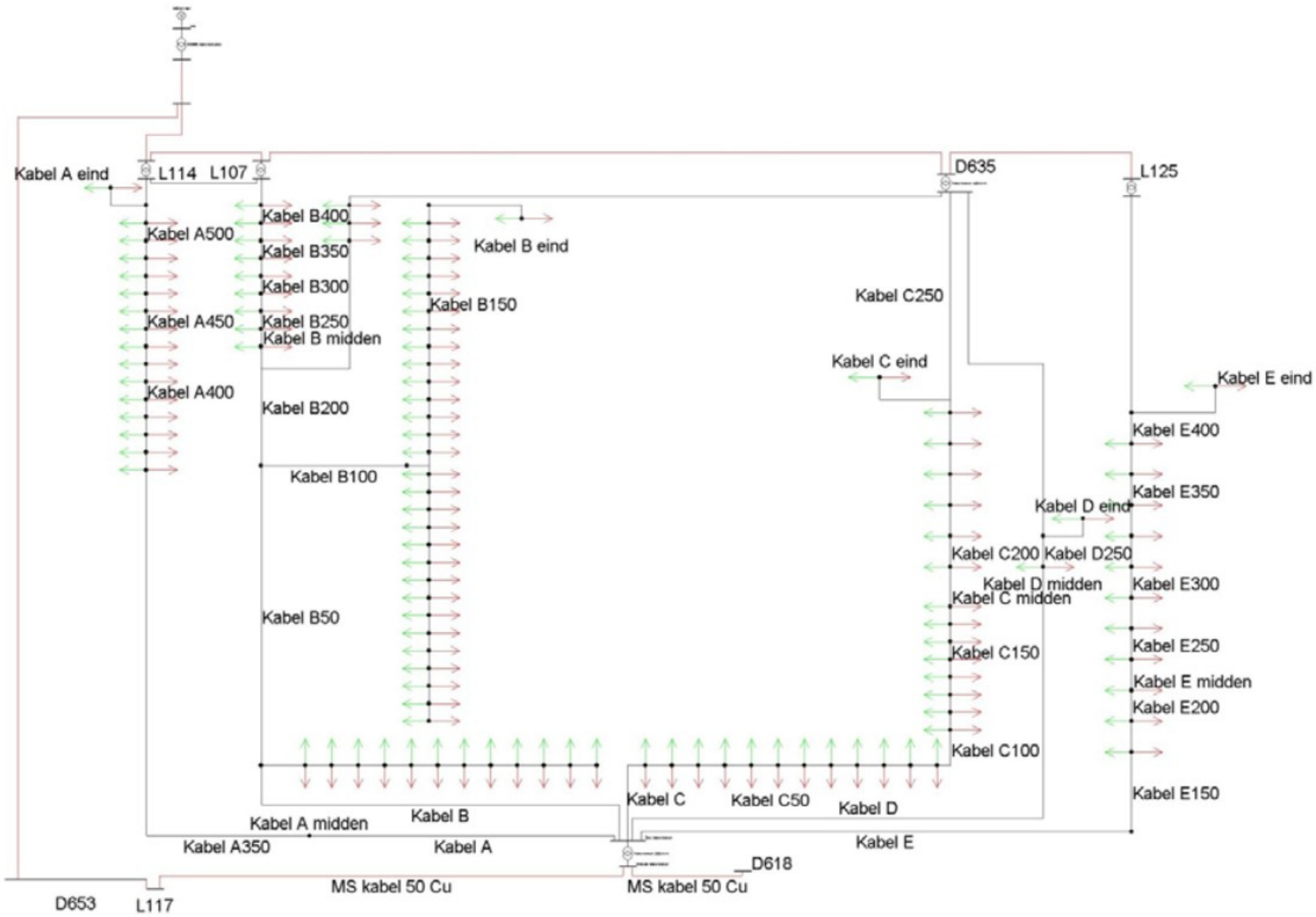

Figure 17: Meshed network structure LV distribution grid of Kijkduin

4.4 Linny-R implementation

In this section, the implementation of the UCP model in Linny-R is discussed. The first part of this section discusses the implementation and related modelling choices of the residential sub-system. Subsequently, the same is discussed for the LV distribution grid. The limitations as a result of the software implementation as well as certain modelling choices will be discussed in the last part of this section.

4.4.1 The system components

Any model to be implemented in Linny-R needs to be converted into products (ovals) and processes (rectangles), since that is how the software is designed. Products can be defined as sources, sinks, buffers and junctions corresponding to production, demand, storage, and nodes respectively. If required, products can also be defined as none of the above (neutral) in order to model various constraints such as losses.

The processes are the decision variables of the UCP model, yet some processes only allow the products (i.e. electricity) to be transported from one product to another according to certain constraints, e.g. the process transporting power from the PV-system to the in-house AC grid (see figure 18). Additionally, the processes can also represent the conversion of the products therewith allowing to include efficiency losses. An explanation of the products, ordered by function, is shown in table 1. The processes that allow the products in the sub-system to move are shown in figure 18.

Functions	Products	Explanation
Sources	PV-system	It produces electricity that can be used for self-consumption, fed into the grid, and be stored in the battery. If all three options are not possible, the electricity is curtailed.
Sinks	Demand Loads	The demand of the residential household is modelled as a sink ensuring that Linny-R solves the system to meet the demand at all times.
Buffers	BES units	The BES unit is modelled as a buffer that can be charged from the PV-system, and discharge towards the grid and the demand load. If none of the above occurs, it still discharges with a relatively small self-discharge rate.
Nodes	In-house Grid	The 'In-house Grid' is modelled as a neutral node that has to be zero at all times. It allows the interaction between the different generation, storage, and demand units in the sub-system as well as the interaction with the LV grid by feeding in or taking of electricity from the LV Grid.
	Sell power to market	This node allows the household to sell surplus PV power to the market via the LV distribution grid
	Buy power from market	Similarly, this node allows the household to buy power in the market via the LV distribution grid in case of shortage.
Others	Total Self-Discharge Losses	The total losses are defined as a "neutral" product with a fixed virtual demand that must be satisfied in order to replicate the self-discharge losses. This deviates from the reality in the sense that the losses are not correlated to the State-Of-Charge of the BES unit.
	Total Curtailment	The total curtailment is a "neutral" product as well allowing the PV-system to curtail surplus electricity if necessary.
	Connection Constraint	The connection constraint allows to set the maximum capacity to the system, while still assigning two different prices for feeding in and extracting power from the grid.

Table 1: Explanation Linny-R software tool functionalities

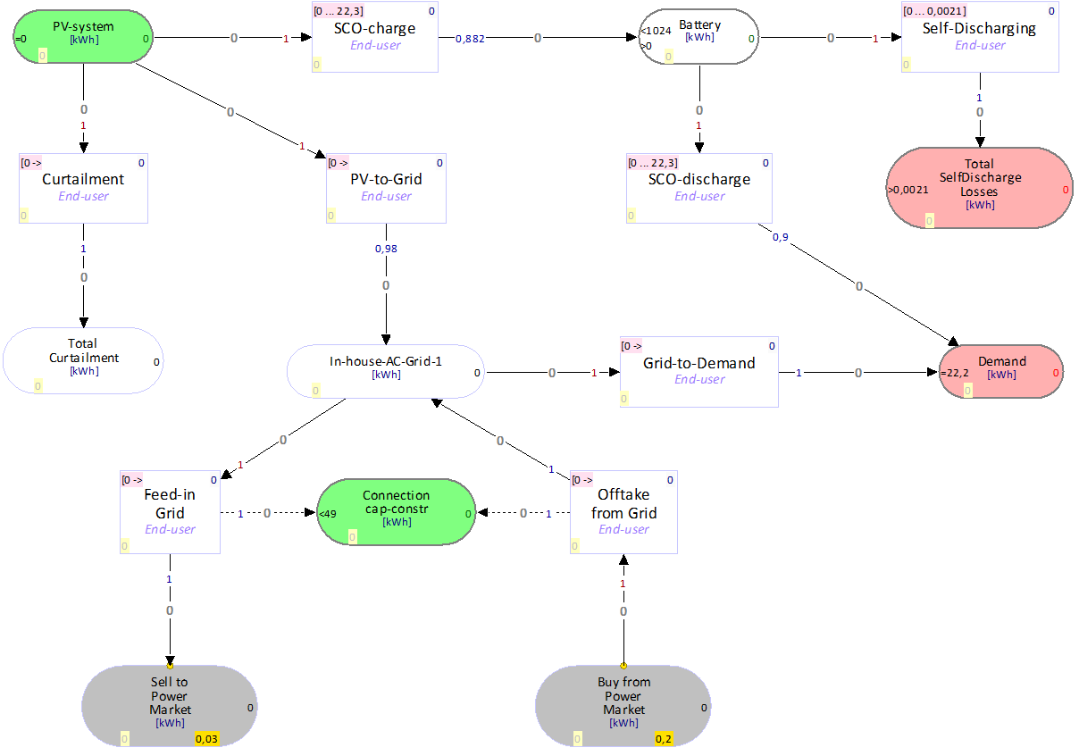

Figure 18: Illustration model implementation in Linny-R

4.4.2 The LV distribution grid system

The model implemented in Linny-R can be used in two distinct ways. On the one hand, it allows to analyze the system from an end-user perspective across various parameters settings. For example by providing the system with various residential demand profiles, PV profiles, BES unit capacities, and electricity prices for both feeding in and extracting power from the grid.

On the other hand, the Linny-R model allows to analyze the system from both the Aggregator and DSO perspective by aggregating the parameters in the data preparation phase according to the assumed PV-system penetration and BES unit penetration rates for a given scenario. The two most important consequences for this modelling choice are found in the demand and PV profiles, which will be discussed in the next section.

4.4.3 Linny-R limitations

The famous statistician George Box (1979) once said: “All models are wrong but some are useful” implying that models should be carefully revised to determine its usefulness. This section describes the limitations of the developed Linny-R model to determine how the simulation results can say something about the system in reality. The most important deviations from reality are the perfect knowledge for a limited period of time and the aggregation of demand and PV profiles, which will be discussed first, followed by some other smaller limitations.

4.4.3.1 Perfect Knowledge to certain extent

First of all, the solver calculates the optimal outcome of the system for each optimization period, therewith reducing its solving time while maintaining the drawbacks of this approach (Hylkema, 2017). Because of this, the software allows to manually set a look-ahead period, which ensures the avoidance of end-state behavior[2] at the end of each optimization period. That means that the solver is able to find a solution for each optimization period based on future time steps that are provided in the data time series. Figure 19 shows this so-called rolling time horizon where each optimization period is calculated according to the look-ahead period. In this study, each optimization period consists of 96 PTUs corresponding to one full day together with a look-ahead of 96 PTUs as well.

The decision for 96 PTUs is based on the assumption that the Aggregator is able to forecast the required information (e.g. weather and demand forecasts) to optimally adjust the BES unit behavior over this period of time, in the same way she has to bid vRES into the wholesale power market. The most important consequence is that the model results show the optimal solution for each optimization period considering no forecast errors.

[2] For example, discharging the BES unit because the remaining storage volume does not contribute to the objective function.

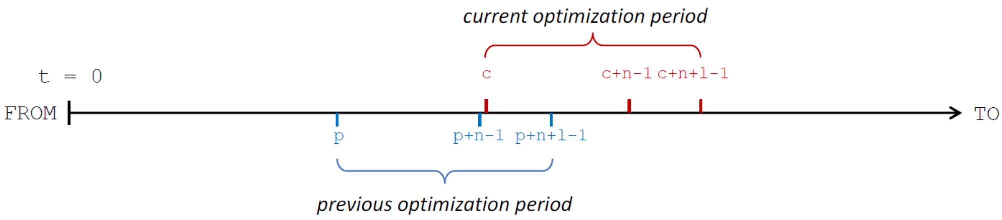

Figure 19: Optimization periods in Linny-R solver (Hylkema, 2017)

4.4.3.2 Demand and PV profile parameter aggregation

Both the demand profiles as the PV profiles are aggregated, resulting in the following implications. First, the demand profile for an individual end-user is composed by factoring the Annual Electricity Consumption (AEC) with the fractions per PTU as will be discussed in section 5.1.1. The fractions themselves are found by measuring the actual power usage at end-users with various connection capacities. Thus, the implication of adopting an average fraction value for a single end-user is primarily found in the fact that the actual values may significantly deviate due to the different lifestyles and corresponding consumption patterns. However, individual deviations are offset when aggregating the average values for each of the 111 end-users located in the LV distribution grid into a single parameter.

Then second, aggregating the PV profiles implies the exact same output for each PV-system located in the distribution grid, while in reality this depends on the angle of the sun relative to the PV-system. Thus the outcomes of the Linny-R simulation, with in particular the impact of feed-in power on the LV substation, deviates from reality in the sense that the actual feed-in peaks may be slightly lower. There is good chance that not all end-users have directed their PV-system panels to the south, on which the computed profiles are based.

Nevertheless, the PV profile values themselves are composed by converting the solar irradiation in [J/m$^{2/}$/PTU] to the energy produced in [kWh/PTU]. That means the output of all individual PV-systems during one PTU deviate from reality in the sense that the actual output, and thus the impact on the LV substation, may be slightly higher on a second to second basis. The slightly lower impact caused by aggregating all PV profiles as discussed in the previous paragraph is therefore to some extent compensated by converting solar irradiation to average PV profile values in [kWh/PTU].

4.4.3.3 Other limitations

Finally, the self-discharge rate in the model is fixed and not proportional to the SOC to avoid additional solving time, while limiting the drawbacks of that approach. The self-discharge rate is 2% per month, meaning that even with an average SOC of 100%, the losses would be 3,24 [kWh/year]. One could argue that this value can also be neglected to even further reduce the solving time. However, it is not worth it to change the model accordingly due to decisions made in the beginning of this study.

5 Value from the end-user perspective

The previous chapter discussed the methodology together with the model set-up and therewith defined the model in terms of variables, parameters and mathematical equations. However, the values for production decisions, as well as the values for the operational and system-wide constraints are still unclear. In particular, the amount of electric flexibility services that could be provided by self-interested end-users by means of aggregation must be further outlined. The following chapter therefore discusses how end-users without an Aggregator could create value by investing in a BES by formulating an answer to the first sub-question:

How much electric flexibility services can be provided by a BES unit connected to the low-voltage distribution grid?

In order to find an answer, the chapter is organized as follows. Section 5.1 first discusses the benefits that end-users, owning various PV-systems, gain by analyzing the self-consumption and self-sufficiency ratios as well as their yearly costs of electricity based on actual demand and PV-production profiles. Subsequently in section 5.2, the BES unit is included to analyze the impact it has on the same output indicators using the Linny-R model. This section therefore also includes the model validation. Whether the reduction of yearly electricity costs cover the total investment costs is elaborated on in 5.2 as well. An experimental design and the results that analyze the possibility for end-users to offer load flexibility to the Aggregated is elaborated on in section 5.3. Finally, an answer to the sub-question is provided in section 5.4 based on the insights gained in this chapter, before moving on to chapter 6 where the Aggregator's perspective is analyzed.

5.1 Self-Consumption and Self-Sufficiency

The value that end-users can capture by installing a BES unit next to their PV-system depends on many factors. First, there is the capacity of the PV-system in [kWp] and the intermittent solar irradiation in [J/m^2] that can be converted into electricity. Then, there is the demand profile of the end-users to be satisfied usually measured in [kWh], and finally the applicable support scheme. The impact of those factors for various types of households and PV-systems are analyzed in the remainder of this section. This starts with the used data sources, followed by the effect that various scenarios may have on the output indicators. The data of section 5.1 is analyzed by means of spreadsheet software.

5.1.1 Datasets

The required data to perform a first analysis regarding the value that end-users capture by installing residential PV-systems is discussed in this section. The two main datasets that are used for this analysis are residential demand profiles and PV-system production profiles. Due availability of data, it is decided to select a timeframe of 2016 with a resolution of 1 PTU (15 minutes) corresponding with 35136 data entries for each data set.

5.1.1.1 Residential demand profiles

The residential demand profiles are retrieved from The Dutch Energy Data Exchange Association (NEDU, 2017). They publish the fractions of the Annual Electricity Consumption (AEC) for each PTU per connection type (e.g. 3x25 [A]). Multiply those fractions with the AEC in [kWh] and the result is an electricity demand profile in [kWh/PTU]. Figure 19 shows the fractions per PTU in 2016, where the seasonal effect is clearly visible. It should be noted that the data consists of the average values for the electricity consumption in a particular PTU, implying that the maximum power through the connection point could deviate in reality.

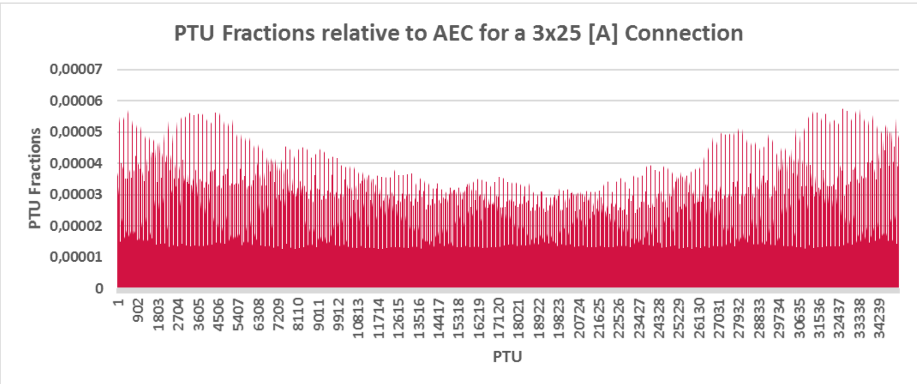

Figure 20: AEC Fractions per PTU for a 3x25 [A] Connection

The HERMES DG 3 project showed that Kijkduin mainly consists of (semi) detached houses (Lumig & Uytterhoeven, 2009). Therefore, it is decided to multiply the fractions with an AEC of 3500 [kWh] to represent an average household, and both 4000 and 5000 [kWh] to represent larger (semi) detached houses. The assumed connection type is 3x25 [A] corresponding to the E1A profile, which is the most occurring connection type in The Netherlands (Gaslicht.com, n.d.)

5.1.1.2 PV-system production profiles

The PV-system production profiles are obtained via the forecasting department at Eneco Energy Trade and based on actual weather data collected at the weather station in Rotterdam. They estimate the output of a PV-system by using the radiation value in [J/m^2] for each PTU and the radiation angle. For this study it is decided to develop annual production profiles for PV-systems sized 3, 4 and 5 [kWp] as these are currently the most common sizes on the market. Figure 20 shows the profiles for a system sized as 5 [kWp]. The seasonal effect is clearly visible, as with the demand profiles in the previous section.

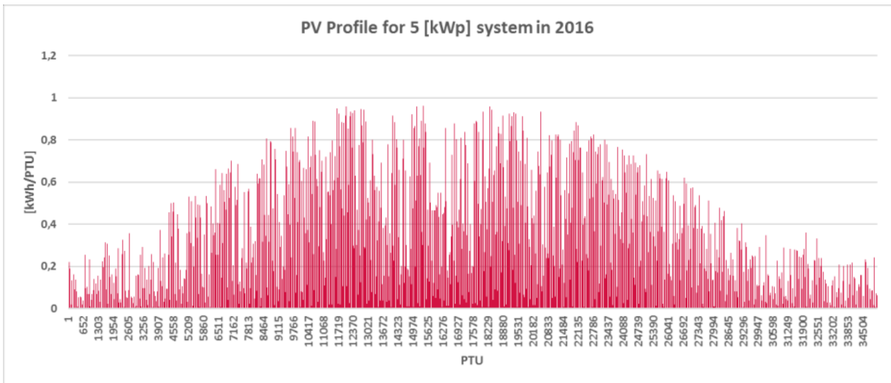

Figure 21: Production profile of PV-system of 5 [kWp] in 2016

5.1.2 Intermediary results

As discussed previously, the value that can be captured by end-users that own a PV-system depends on many factors. The self-sufficiency and self-consumption ratio are good output indicators to analyze how much benefit is created via the PV-system from two different perspectives. Once again, the *self-sufficiency* (SS) ratio describes how the PV-system covers the need from cash-flow perspective, and thus can be affected by a supporting scheme such as net-metering. However, the *self-consumption* (SC) ratio only describes the local utilization of the PV-system output from an energy perspective and thus is not affected by any financial support scheme.

This section discusses the intermediary results by means of spreadsheet calculations based on the residential demand profiles and PV-system profiles as discussed in 5.1.1. The insights gained in this section will be used as a benchmark before analyzing the effect of including a BES unit.

5.1.2.1 Yearly Costs of Electricity

The benefit that end-users with a PV-system create is found in the ability to lower their electricity bill, since they can produce their own electricity, and therewith reduce their needs to extract power from the grid. Figure 21 shows the yearly costs of electricity for end-users with an AEC of 3511, 4012, and 5015 [kWh] based on the price of electricity ranging from 0,15 to 0,20 [€/kWh]. The values in the graph differ slightly with those identified earlier, since the PTU fractions do not exactly add up to 1, probably due to round up differences. This would however not impact the results significantly. The graph shows the total costs of electricity ranging between approximately 500 and 1000 [€/year], depending on the electricity price and the AEC.

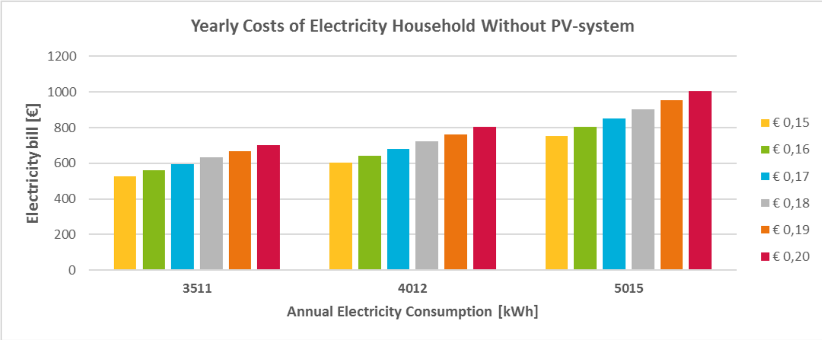

Figure 22: Yearly Costs of Electricity for Household without PV-system

5.1.2.2 PV-system with Net-metering Policy

The current net-metering policy strongly affects the yearly costs of electricity. Figure 22 shows the total costs of electricity, in a similar way as shown in the previous figure. However, the net-metering policy ensures that the surplus electricity at any moment in time can be fed into the grid, therewith directly reducing the electricity bill. That explains the different results as compared with figure 21, since the full annual PV-system output valued in [€] can be subtracted from the total demand valued in [€] regardless the actual time-of-use.

Note that net-metering allows end-users to create a negative electricity bill. That is the case when the PV-system produced more than the end-user needs on a yearly basis. The compensation for this surplus is however valued according to the wholesale market price, which in this case is defined as 0,03 [€/kWh].

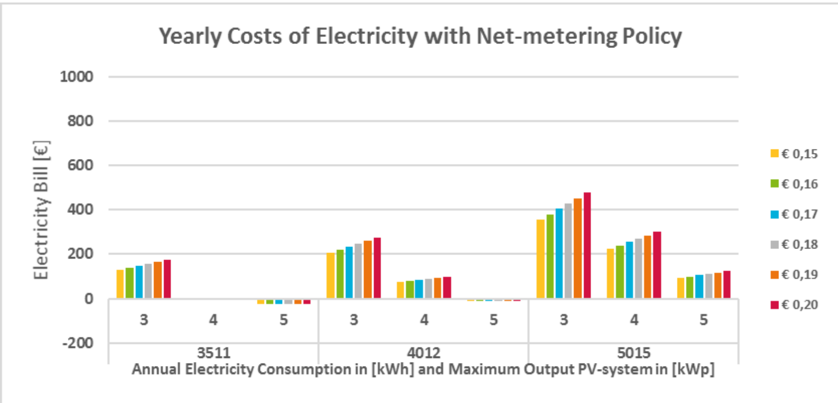

Figure 23: Yearly Costs of Electricity per AEC and PV-system Capacity with Net-metering Policy

It is clear from figure 22 that significant cost reductions can be achieved for all configurations. The yearly costs of electricity, in this case range between 0 and approximately 450 [€/year] depending on the electricity price, PV-system and AEC.

The self-sufficiency ratios for the configurations with an electricity bill of zero are clear, since they have to be 100% or higher. They are able to produce more electricity with their PV-system then they need on a yearly basis. Figure 23 shows the self-sufficiency ratios for the other configurations. For the sake of simplicity, the ratios are only compared with the electricity price of 0,20 [€/kWh].

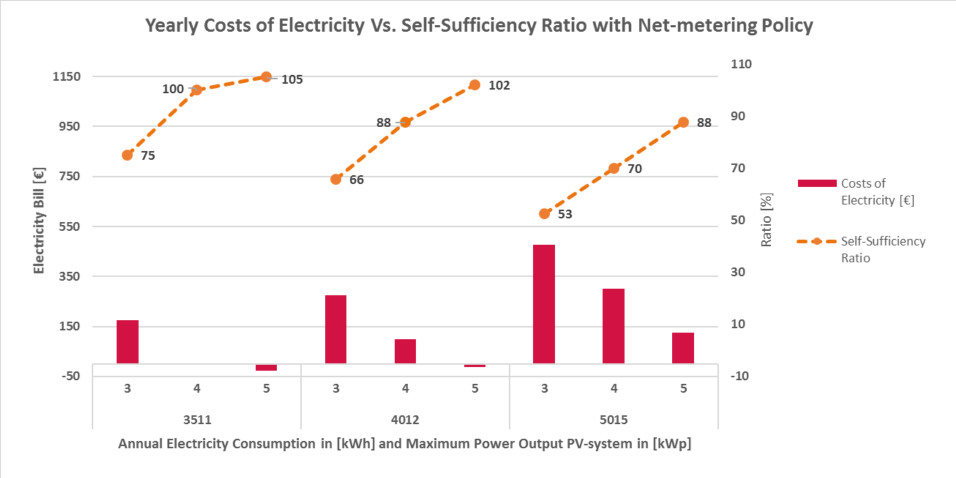

Figure 24: Yearly Costs of Electricity and Self-Sufficiency Ratio with Net-metering Policy

Furthermore, the graph shows that the self-sufficiency ratio increases with the size of the PV-system. Similarly, the ratio decreases proportionally with the AEC of the end-user, keeping the size of the PV-system capacity equal. Admittedly, these results do not show any new insights as to what one would expect. Therefore, the next section includes the self-consumption ratio which only accounts for the utilized PV production.

5.1.2.3 PV-system with different support scheme

The support scheme net-metering that incentivizes PV-system integration is assumed to be subject to change in 2020 as described in the most recent governmental coalition agreement (VVD, CDA, D66, & ChristenUnie, 2017). The exact changes are however still uncertain. Nonetheless, in this research it is assumed that the changes will be in favor of incentivizing storage solutions such as residential BES units. For example, in case the feed-in tariff for PV-system electricity is lower than the retail price. Hence, it is assumed that for the remainder of this study, the feed-in tariff will be equal to the average wholesale market price.

The future regarding wholesale electricity prices is uncertain and difficult to predict. Figure 24 shows the average price on the APX spot market of 2017 and the corresponding linear trend line, which is heading towards the 30 [€/MWh]. This value is assumed to be the feed-in tariff in the remainder of this study.

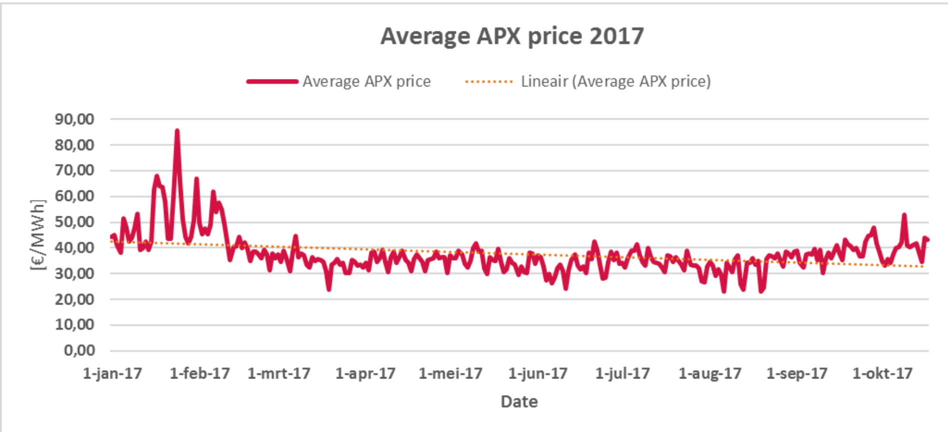

Figure 25: Average wholesale APX price from Jan 2017 - Okt 2017

It is assumed that all surplus electricity produced by the PV-system is fed into the grid when calculating the self-consumption ratios for the different configurations. Figure 25 illustrates a typical summer week for an average household with an AEC of 3500 [kWh] and a PV-system of 3 [kWp]. The self-consumption ratio is calculated by dividing the orange surface below the red line by the total orange surface per year as earlier discussed in section 3.4.2. The orange surface above the red line is fed into the grid at a price of 0,03 [€/kWh] and therefore does not affect the self-consumption ratio, but only the self-sufficiency ratio.

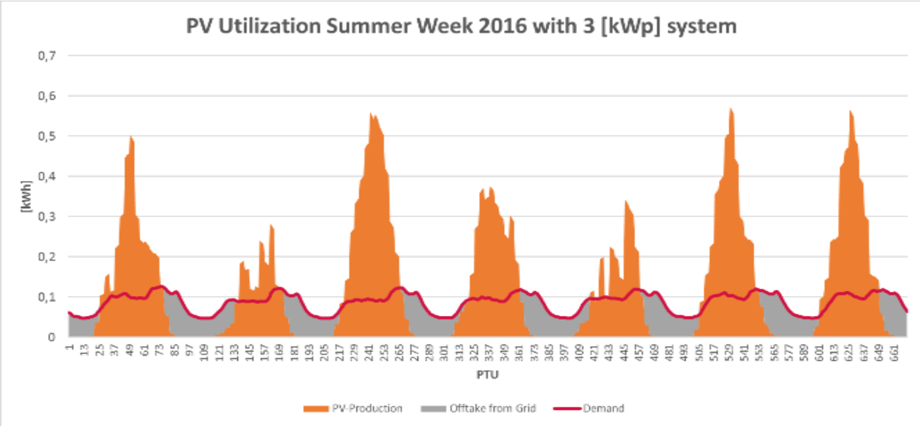

Figure 26: PV Utilization Summer Week 2016 with 3 [kWp] PV-system

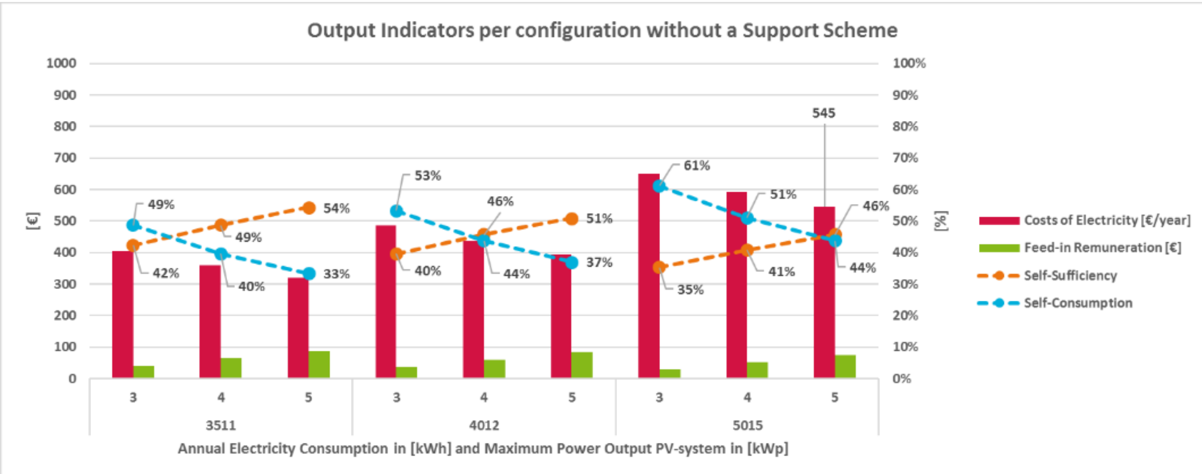

Figure 27: Output Indicators per configuration without a financial Support Scheme

The self-sufficiency ratio, self-consumption ratio and yearly costs of electricity for each configuration all come together in figure 26 to better understand the impact of removing the support scheme on the value to be captured by end-users. For simplicity, the results are based on a retail price of 0,20 [€/kWh] and a feed-in price of 0,03 [€/kWh] allowing to clearly visualize the outcomes for each configuration.

The results show a self-sufficiency and self-consumption ratio of 35-54% and 35-60% respectively, depending on the configuration. Adding extra PV-system capacity results in an increased self-sufficiency ratio and while reducing the yearly costs of electricity, but at the same time decreases the self-consumption ratio. Net-metering policy ensures that the remuneration for electricity fed into the grid increases proportionally with the size of the PV-system.

The perceived value of a PV-system for an end-user is therefore mainly determined by the relative valuation of the self-sufficiency and self-consumption ratio. Thus, it represents a trade-off between an economical advantage and an expected positive contribution in terms of sustainability. Important to note is that a decreasing self-consumption ratio due to PV-system expansion does not automatically also reduce the contribution to a more sustainable electricity system. The absolute volume of zero-carbon electricity that is fed into the grid still increases when expanding the size of the PV-system.

Residential BES units are expected to significantly improve both the economic advantages as well as the sustainability contribution. On the one hand, they allow to improve locally produced PV utilization, therewith increasing the self-consumption ratio. Whereas on the other hand in a scenario without a financial support scheme, end-users could improve their self-sufficiency ratio, creating an economic benefit as well. The next section applies a similar analysis using the same data, but introduces the utilization of a residential BES unit to outline the potential benefits for end-users. An important difference compared with the previous analysis is the usage of the developed Linny-R model to simulate the behaviour of the BES unit, which will be elaborated on in the next section.

5.2 Including the BES Unit

The chapter so far discussed the data sets, provided some intermediary results using spreadsheet calculations, and discussed the removal of the support scheme as assumed in this study. If, and to what degree residential BES units could affect the output indicators under this removal is however still unclear.

There are multiple approaches to replicate the charging and discharging behavior of a residential BES unit in the defined system. However, the tool selected in this study is the Linny-R model based on LP. The identified sub-system (i.e. a household) that is implemented in Linny-R as discussed in section 4.3 is used to simulate the behavior of the BES unit, since it is easy to operate, and to test whether the sub-system is implemented correctly for later purposes. Section 5.2.1 and 5.2.2 validate the model to make sure it replicates the correct behavior of the BES unit in the system. The sections thereafter describe the reference case, an NPV calculation to analyze the profitability of investing in a BES unit, and finally a sensitivity analysis before implementing the Aggregator, which is discussed in in chapter 6.

5.2.1 Charging/Discharging behavior

The most important mechanism that should be replicated by the Linny-R model is the ability of the BES unit to charge electricity generated by the PV-system and discharge electricity to meet local demand, also referred to as Self-Consumption Optimization (SCO). The behavior of the BES unit exclusively for the purpose of SCO is expected to have a direct relationship with the amount of generated electricity from the PV-system. Surplus electricity causes the BES unit to charge, whereas a shortage results in discharging.

This suggests the following hypothesis:

Hypothesis 1: The charging/discharging behavior of a residential BES unit is directly related to the local PV production

To test this hypothesis, two time series with significantly different PV production profiles, a summer and winter month, are implemented as parameters in the model. Table 2 shows any other important parameters assumptions. The notion ‘optimize 96 PTUs at a time with a look-ahead period of 96 PTUs’ at the bottom of table 2, refers to the minimization of total system costs considering the degrees of freedom and constraints as discussed in section 4.2 for one full day under the assumption of perfect information for the next day.

General		
Timeframe: 2976 PTU’s in July/January		
Parameter	**Value**	**Unit**
AEC	3500	[kWh/year]
Max Connection Capacity	7,5	[kWh]
Retail price of electricity	0,2	[€/kWh]
Wholesale price of electricity	0,03	[€/kWh]
PV-system Capacity	3	[kWp]
PV inverter efficiency	98	[%]
BES Unit Energy Capacity	13,5	[kWh]
BES Unit Power Capacity	1,25 (=5 kW)	[kWh/PTU]
BES Unit Inverter Capacity	90	[%]
Initial State-of-Charge	6,75	[kWh]
Self-discharge Rate	0	[%]
Solver Settings		
Optimize 96 PTUs at a time from 1 to 2976 with a look-ahead period of 96 PTUs		

Table 2: Parameter settings to study Hypothesis 1

Figure 28 shows the optimization results by means of the State-Of-Charge (SOC) of the BES unit (Battery-1:Stock) for a typical summer month (July) in 2016. Note that the PV production (SolarPV-1:Stock) parameter is modelled as a negative value because of Linny-R characteristics. The graph shows that the BES unit completely discharges from the start since the available PV power on the first day is relatively low.

After the first day, the BES unit is charged and discharged depending on the available PV power during the day. This is clearly visible around approximately the 400th PTU where less PV power is available compared with the previous three days, resulting in a lower SOC on the next day as compared with the rest of the month. Furthermore, the BES unit starts to gradually discharge towards the end of the simulation since the Linny-R solver tries to minimize the total system costs. Hence, all zero-cost PV-system electricity stored in the BES unit is utilized, previously referred to as end-state behavior.

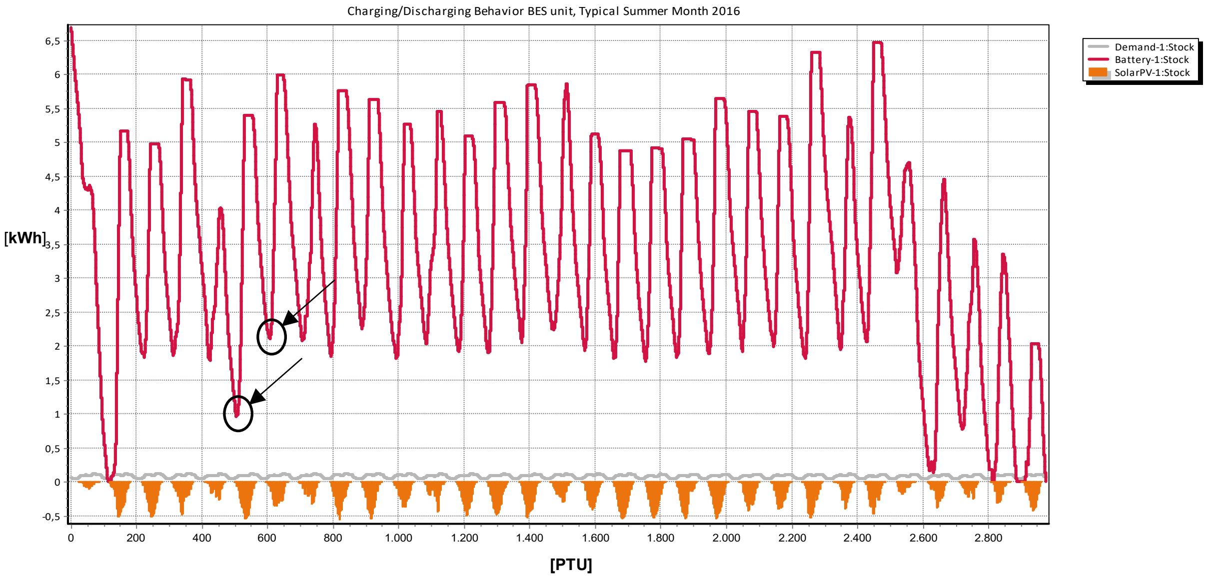

Figure 28: BES unit behavior in a typical summer month in 2016

Figure 29 shows a similar plot but for a typical winter month in 2016 where it clearly shows that the BES unit discharges straight away in order to satisfy local demand that cannot by supplied by the PV-system. The available PV power during this month is small, explaining the almost empty BES unit during the whole month. Only some minor peaks in PV power that could not be utilized to satisfy the local demand directly, are stored in the BES unit, e.g. at approximately the 2400th and 2650th PTU.

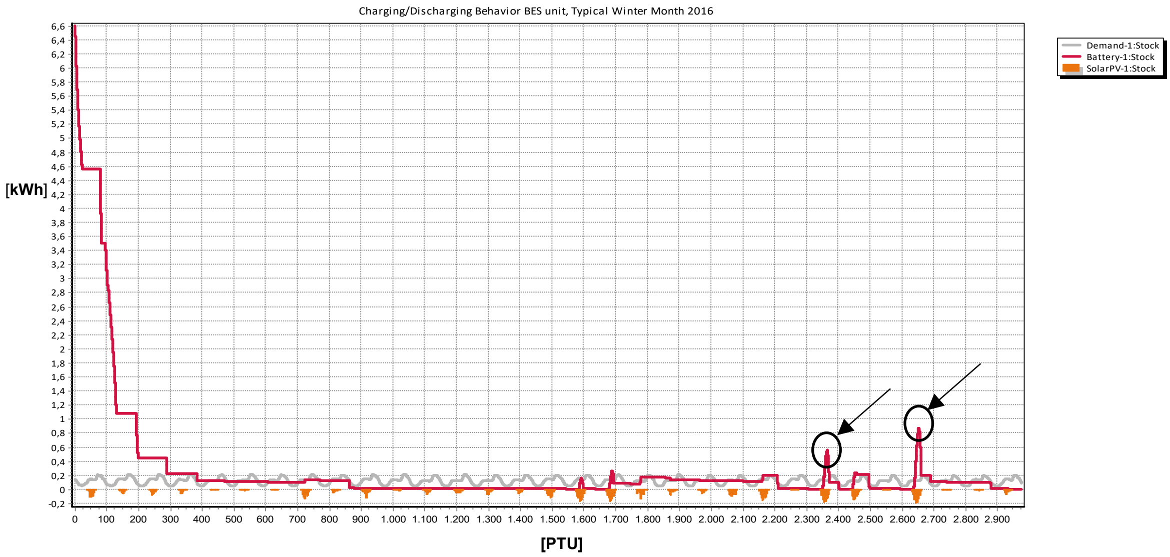

Figure 29: BES unit behavior in a typical winter month in 2016

These results indeed show a direct relation between the available PV power and the charging/discharging behavior of the BES unit. Hence, hypothesis 1 can be confirmed.

5.2.2 Feeding in or Curtailing PV power

Studying hypothesis 1 validates the charging/discharging behavior of the BES unit itself. However, the other system components need to be validated as well. In particular the possibility of the PV-system to feed power into the grid and to curtail if necessary. The former should always be preferred over curtailment due to the revenues generated by feeding in. This leads to the following hypothesis:

Hypothesis 2: The system prefers feeding in PV power over curtailment of PV power

To test this hypothesis, the same time series of the summer month are used as before. The difference is found in blocking the charge and discharge processes of the BES unit, therewith replicating the inability to use the BES unit. All surplus PV power is then expected to be fed into the grid. Additionally, the connection capacity is constraint at 0,3 [kWh/PTU], therewith replicating a local congestion that can only be solved by curtailment. Table 3 shows the parameter assumptions for this test where the cells highlighted in blue are the values that are changed compared with the parameter settings provided in table 2.

General		
Timeframe: 2976 PTU's in July		
Parameter	**Value**	**Unit**
AEC	3500	[kWh/year]
Max Connection Capacity	0,3	[kWh/PTU]
Retail price of electricity	0,2	[€/kWh]
Wholesale price of electricity	0,03	[€/kWh]
PV-system Capacity	3	[kWp]
PV inverter efficiency	98	[%]
BES Unit Energy Capacity	n/a	[kWh]
BES Unit Power Capacity	0	[kWh/PTU]
BES Unit Inverter Capacity	n/a	[%]
Initial State-of-Charge	n/a	[kWh]
Self-discharge Rate	n/a	[%]
Solver Settings		
Optimize 96 PTUs at a time from 1 to 2976 with a look-ahead period of 96 PTUs		

Table 3: Parameter settings to study Hypothesis 2

Figure 30 shows the Linny-R model output of the parameter input of table 3. The green lines show the amount of power fed into the grid, while the lines in black represent the power curtailed. It is clearly visible that power is only curtailed in case the green lines reach their maximum of 0,3 [kWh/PTU], e.g. power is curtailed three times in area circled in red. Hence, hypothesis 2 can be confirmed.

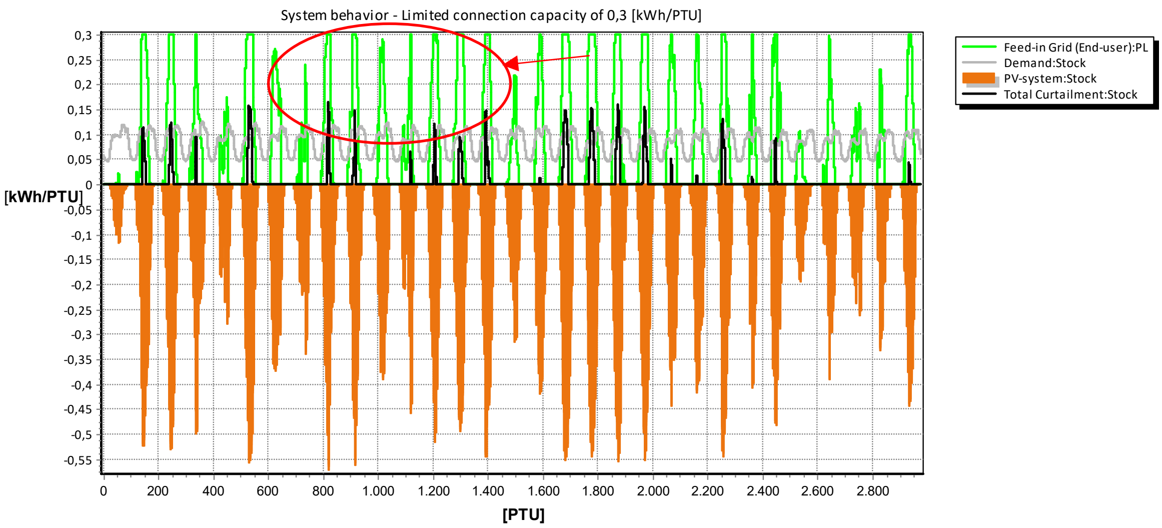

Figure 30: Feed-in and Curtail Behavior of the System in summer month 2016

5.2.3 Reference Case end-user Analysis

The previous section showed that all core model mechanisms are implemented correctly, and confirmed that the modelled BES unit behaves as expected. That means we can now use the model to analyze the system over time while applying different parameter settings. In order to reduce the scope of the research, a reference case is selected for just one household configuration instead of the nine different configurations analyzed section 5.1.

Both the focus of this research as well as the selected distribution grid to use for a case-study are leading factors for selecting a reference scenario. The former refers to the possibility for using electric flexibility services to reduce the costs of congestion management in distribution grids, and the latter to the relatively large households connected to the grid in Kijkduin. An end-user with an AEC of 5000 [kWh] and a PV-system capacity of 5 [kWp] is therefore selected as reference case since such households are expected to cause the most congestions. Table 4 shows the parameter settings for the reference case scenario and the resulting output indicators generating the output as shown in figure 30. Once again, the notion 'optimize 96 PTUs at a time with a look-ahead time of 96 PTUs' at the solver settings section in table 2, refers to the minimization of total system costs considering the degrees of freedom and constraints as discussed in section 4.2 for one full day, under the assumption of perfect information for the next day.

General		
Timeframe: 35136 PTU's in 2016		
Parameter	**Value**	**Unit**
AEC-profile	5015	[kWh/year]
PV-system Capacity	5	[kWp]
PV inverter efficiency	98	[%]
BES Unit Energy Capacity	13,5	[kWh]
BES Unit Power Capacity	1,25 (=5 kW)	[kWh/PTU]
BES Unit Inverter Capacity	90	[%]
Initial State-of-Charge	6,75	[kWh]
Self-discharge Rate	25%	[%]
Max Connection Capacity	7,5	[kWh]
Retail price of electricity	0,2	[€/kWh]
Wholesale price of electricity	0,03	[€/kWh]
Solver Settings		
Optimize 96 PTUs at a time from 1 to 35136 with a look-ahead period of 96 days		
Output Indicators		
Self-Sufficiency Ratio	64	[%]
Self-Consumption Ratio	70,8	[%]
Costs of Electricity	353	[€/year]

Table 4: Parameter settings Reference Case End-user perspective

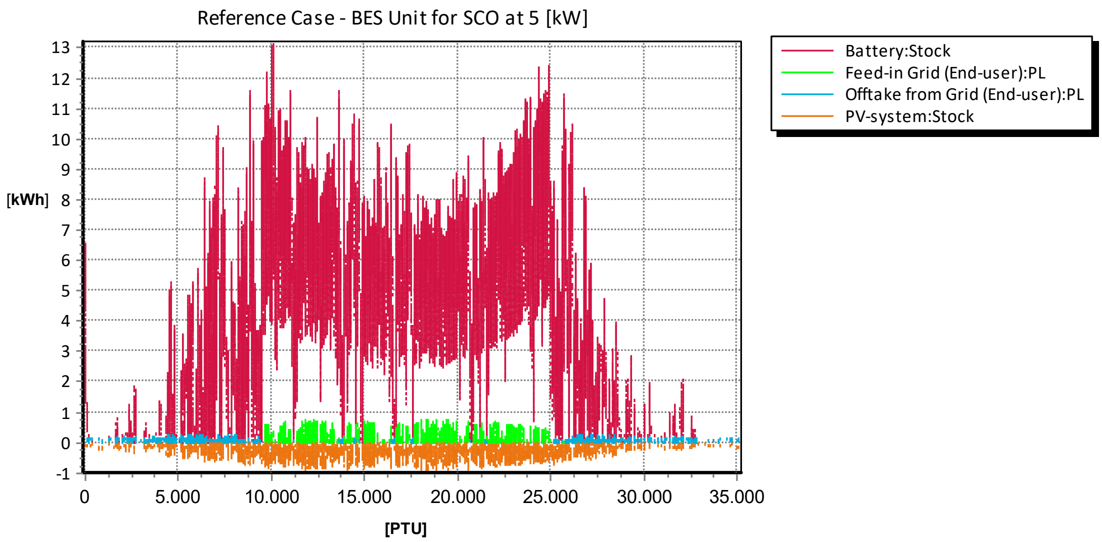

Figure 31: Linny-R simulation output Reference Case

The three developments that are visible in graph 31 and deserve some discussion before continuing with the output indicators are the feed-in and offtake shown in green and blue respectively, and the U-shape shown in red. Starting with the former, both the feed-in and offtake of power to and from the grid are clearly related to the seasons. The available PV power is relatively low during the winter causing the system to extract power from the grid in contrast with the summer where electricity is rather fed into the grid caused by a relatively high PV power availability.

Note that power is fed into the grid at times when the BES unit still had energy capacity left to store any surplus PV power. This is caused by look-ahead period of 96 PTUs. The model minimizes the total costs of electricity for each optimization period implying that the BES unit is charged exactly up to the required power needed for the next period. Feeding in is rewarded by 0,03 [€/kWh] meaning that the system tends towards feeding power into the grid in case the BES unit is sufficiently able to supply the needs of the end-user in the next optimization period. In other words, more profits are generated when power is fed in as compared with storing all available PV surplus power into the BES unit.

This does however not explain the U-shape of the BES unit's SOC (Battery:Stock), which is the result of the seasonal variation in the demand profile as shown in 5.1.1.1. The BES unit simply stores less power due to the reduced power demand of an end-user during the summer.

Finally, investing in a residential BES unit show considerably better output parameters compared with the intermediary results shown in section 5.1.2. The self-sufficiency and self-consumption ratios increased to 64% and 70,8% respectively compared with 46% and 44% without a residential BES unit. Nonetheless, whether investing in a BES unit is economically viable mainly depends on the yearly costs of electricity. These costs decreased from 545 to 353 [€/year] therewith generating a yearly economic benefit of 192 [€/year].

5.2.4 Economic viability of investing in residential BES units

The insight gained in the previous section, in particular the yearly economic benefit in [€/year], allows to use the NPV calculation as shown in section 3.4.1.3 in order to determine the economic viability of investing in a residential BES unit. The assumed initial investment costs are 7500 [€] for the BES unit whereas the future cash flows are considered 192 [€/year] over the timespan of 15 years. Each NPV is calculated with a discount rate of 1%, 3% and 5%. In these scenarios, not a single NPV calculation indicates a viable investment with the most positive scenario of 1% discount rate giving a NPV of -4800 [€] over 15 years. This does not even consider the fact that the product warranty is defined as 10 years, corresponding with a NPV of -5700 [€].

One could therefore argue that investing in a residential BES unit is not viable in any scenario. However, the future cash flows are not adjusted yet for the premium $\lambda^{FlexPremium}$ that end-users receive for selling load flexibility. Figure 32 provides the results of the NPV calculations when including this premium at 500 [€/year].

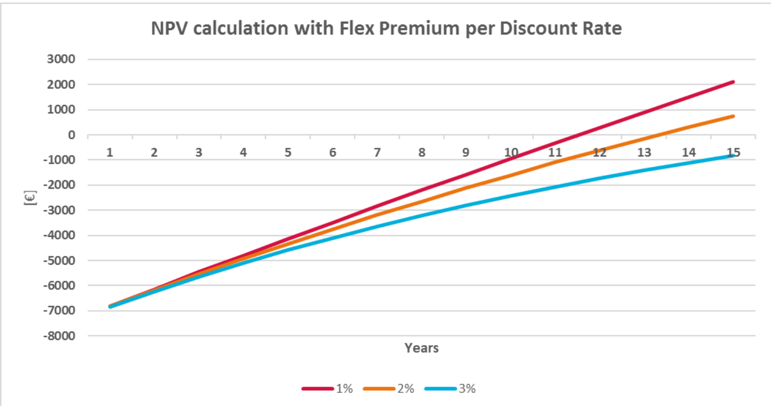

Figure 32: NPV calculation per discount rate

The three lines show the possibility for a viable investment (i.e. a positive NPV value), although it is a rather risky one. None of the NPV scenarios (i.e. discount rates) ensure that the initial investment is earned back before the given product warranty. The viability of the investment therefore strongly depends on the lifetime of the BES unit and the remaining energy capacity as a result of battery degradation. The remainder of this section puts the NPV calculations shown in figure 31 in perspective by discussing the life expectancy, battery degradation, and other uncertainties in future cash flows that affect the NPV over time.

5.2.4.1 Life time expectancy and battery degradation

The BES unit should be operational for at least 12 years in order to obtain a positive NPV value for the investment. Although the manufacturer of the BES unit analyzed in this study did not publish any life time expectancy data, it can be reasonably assumed that the BES unit will have a lifetime equal to at least 1,5 times the product warranty. Similarly, no data or estimations are provided by the manufacturer regarding the battery degradation, since it depends on many factors.

Table 5 indicates the number of PTUs that the BES unit would not be able deliver SCO to its full extent when the energy capacity degrades to that value over time for the reference case. For example, the BES unit would not be able to provide all required SCO services in 4,46% of the PTUs in a year when the energy capacity degrades to 70%. Whether this would affect the future cash flows (i.e. avoided costs of electricity) is discussed in the next section.

SOC [%]	90	80	70	60	50
Frequency PTUs > SOC [#]	69	405	1567	3487	6509
Share of total PTUs [%]	0,20%	1,15%	4,46%	9,92%	18,53%

Table 5: Expected impact of Battery Degradation

5.2.4.2 Sensitivity of NPV analysis

Other important uncertainties that are considered to have an impact on the future cash flows are found in the electricity prices for feed-in and offtake on the one hand, and the possibility of additional use cases for the Aggregator on the other. Therefore, figure 33 shows the results of a sensitivity analysis when varying either the yearly cash flows as the result of SCO or the flex premium provided by the Aggregator. The results show exactly what one would expect. Increasing the flex premium reduces the payback period with up to 2 years, where improved SCO could reduce the payback period with a maximum of 1 year.

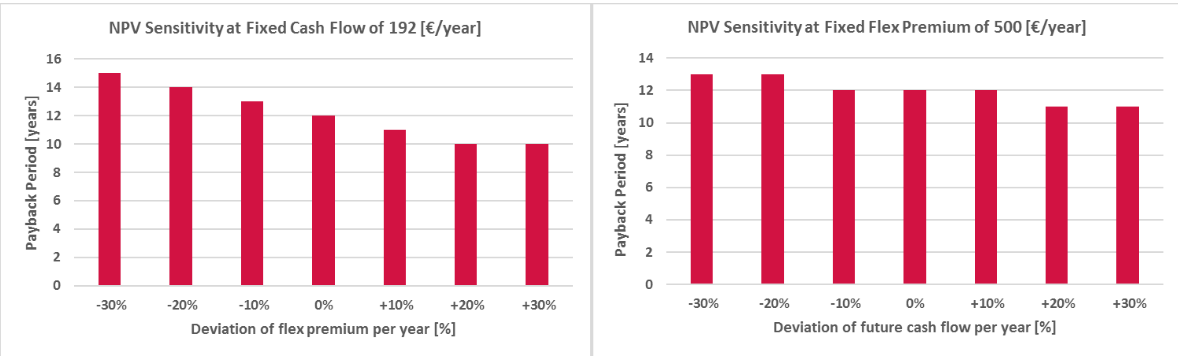

Figure 33: Sensitivity of Flex Premium and Future Cash Flows on Payback Period

Altogether, the life expectancy is assumed to be 15 years, causing no problems for any of the calculated NPV scenarios as long as the Aggregator ensures the critical flex premium. The degradation of energy capacity over time might reduce the future cash flows generated by SCO, although the capacity could drop to 70% while still being able to provide SCO for 95% of the time during the year. It can thus be concluded that, under normal operation and the assurance of a flex premium of at least 500 [€/year], it is economically viable for an end-user to invest in a residential BES unit.

5.3 Power vs. Energy Capacity

The reference scenario discussed in section 5.2.2 combined with NPV analysis in the previous section showed that it could be economically viable for end-users to invest in residential BES units under certain conditions. Most critical is the involvement of the Aggregator to generate additional cash flows that the end-user would not be able to generate by himself. Therefore, this section continues with that idea and analyzes the behavior of the BES unit in more detail to identify the consequences of load flexibility offered by the end-user to the Aggregator. Or in other words, what is the impact of sharing the BES unit between the two entities?

The outputs generated by the Linny-R model for the reference case are the starting point for this analysis, which can be considered as a sensitivity analysis. Figure 34 shows the charging and discharging behavior that produced the BES unit's SOC as shown in figure 31. The previously discussed U-shape is clearly visible again in the discharging output per PTU (SCO-discharge-1 (End-user):PL) for the same reason that it simply follows the demand profile.

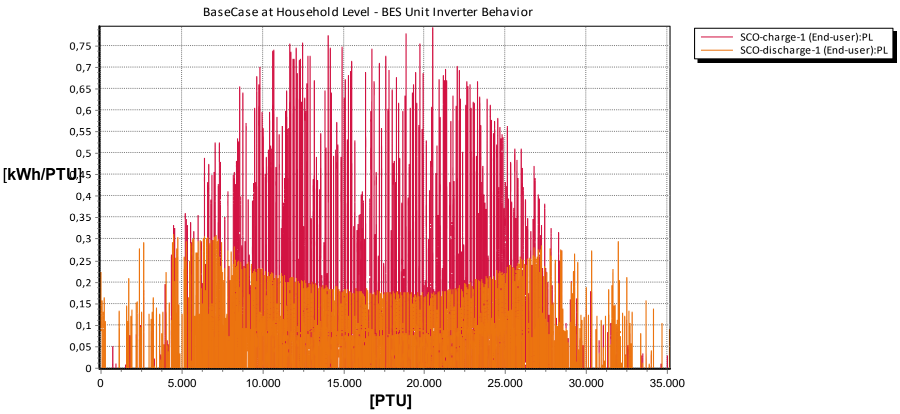

Figure 34: Charging and Discharging Output in Reference Case

Furthermore, the inverter is never fully utilized at 1,25 [kWh/PTU] during the whole year, which implies an opportunity for the Aggregator to use the remaining power capacity. Especially since we already know that the energy capacity of the BES unit is not utilized to its maximum either. This leads to the following hypothesis:

Hypothesis 3: Decreasing inverter capacity assigned to SCO does not affect the output indicators for end-users significantly

The Linny-R model is consulted to test this hypothesis, where all the parameters used for the reference case stay the same while varying the power and energy capacity of the inverter and BES unit respectively. Table 6 shows the experimental design regarding the input parameters and the corresponding output indicators for this analysis. Note that the inverter capacity is given in [kW], but implemented as [kWh/PTU] into the Linny-R model.

The first four scenarios reduce the power capacity while the energy capacity is fixed at 13,5 [kWh], followed by scenarios that reduce the energy capacity while fixing the power capacity at 5 [kW].

Input Parameters			Output Indicators		
Scenario	**BES Power [kW]**	**BES Energy [kWh]**	**SS [%]**	**SC [%]**	**Cost of Electricity [€/year]**
1	5	13,5	64,7	70,8	355
2	3	13,5	64,7	70,8	354
3	2	13,5	64,7	70,7	354
4	1	13,5	63,0	68,4	371
5	5	10	64,6	70,5	355
6	5	8	64,0	69,7	361
7	5	6	62,6	67,8	375

Table 6: Input Parameters and Output Indicators of Power/Energy Analysis

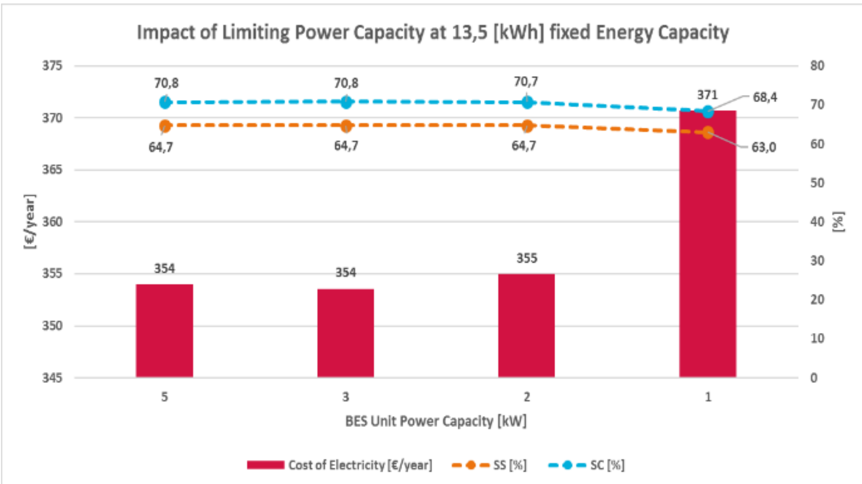

Figure 35: Output Indicators when Limiting Power Capacity

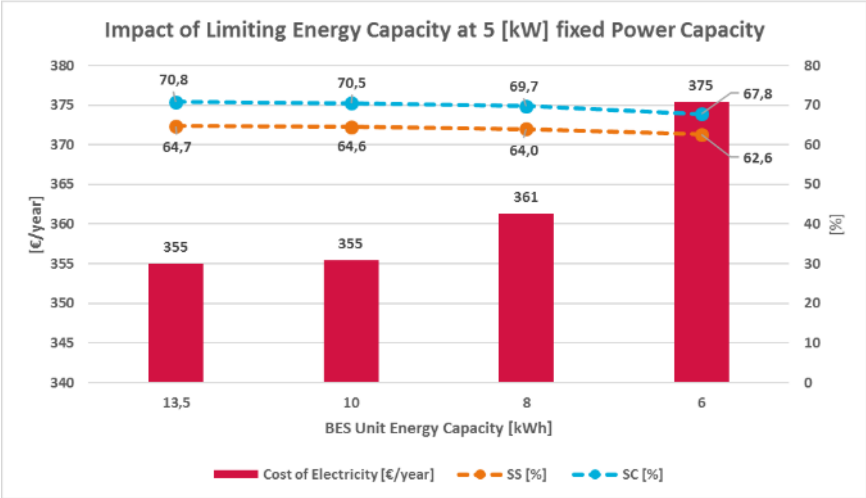

Figure 36: Output Indicators when Limiting Energy Capacity

Figures 35 and 36 plot the results of table 6 to clearly visualize the differences per scenario. They show that decreasing the BES unit's power capacity starts affecting the output indicators once it reaches 1 [kW]. The SS and SC ratios decrease with 1,7% and 2,4% to 63% and 68,4% respectively, where the costs of electricity increase with 17 [€/year] to 371 [€/year] both compared with the output indicators at 5 [kW].

Decreasing the BES unit's energy capacity starts affecting the output indicators at 8 [kWh] and even more at 6 [kWh]. The SS and SC ratios at 6 [kWh] decrease with 2,1% and 3% to 62,6% and 67,8% respectively, where the costs of electricity increase with 20 [€/year] to 375 [€/year], both compared with the output indicators at 13,5 [kWh].

Based on this information, two main conclusions can be drawn. On the one hand, limiting the power capacity of the BES unit does not significantly affect the output indicators, therewith creating an opportunity for the Aggregator to use this capacity for other services such as balancing power. Hence, hypothesis 3 can be confirmed.

On the other hand, limiting the energy capacity does not significantly affect the output indicators either, therewith allowing the BES unit to degrade over time without generating any negative results for end-users.

5.4 Conclusions on BES unit availability for flexibility services

Chapter 5 discussed the potential value that could be created by investing in a residential BES unit from the end-user perspective through analysis of the defined output indicators for PV owners, by including a BES unit using the Linny-R model, and via analyzing the power/energy capacity in more detail to identify opportunities for both the end-user and the Aggregator. Based on the gained insights, this section aims to formulate an answer to the following sub-question.

How much electric flexibility services can be provided by a BES unit connected to the low-voltage distribution grid?

First of all, section 5.1 showed that PV owners can achieve a SS and SC ratio of 35-54% and 35-60% respectively depending on the configuration. The selected configuration to analyze in the remainder of this research is a household with an AEC of 5015 [kWh] and a PV-system with [kWp] power capacity.

Section 5.2 includes the BES unit in the analysis by means of the developed Linny-R model. The model's effectiveness in simulating a BES unit is tested, and the results show significant improvements for each of the defined output indicators with a 192 [€/year] reduction in yearly costs of electricity being the most important one. This value is subsequently used to calculate the NPV indicator to determine the economic viability of investing in a residential BES unit. The results are questionable in the sense that the expected life time and battery degradation are unknown, but show profitability in certain conditions with the need for an Aggregator as the most important condition.

The last section analyzed the behavior of the BES unit for the reference case in more detail by designing 7 experiments to test whether the end-user is able to sell power and energy capacity without sacrificing their own benefits. The analysis showed that the output indicators do not significantly change when limiting the power and energy capacity of the BES unit, therewith creating an opportunity for the Aggregator to use the BES unit for other services up to 4 [kW].

Thus based on these insights and assumptions, it can be concluded that a single BES unit could offer at least 3 [kW], but up to 4 [kW] of power capacity, and similarly offer at least 3,5 [kWh] up to 7,5 [kWh] of energy capacity to the Aggregator while still ensuring the economic viability of investment for end-users. The next chapter includes the Aggregator in the analysis to determine the potential value created by BES units connected to the LV distribution grid from that perspective.

6 Value from the aggregator perspective

The previous chapter analyzed the potential value of a residential BES unit from the end-user perspective and showed the need of an Aggregator to ensure a profitable investment by allowing end-users to offer load flexibility and therewith generate additional cash flows. Optimization from the end-user perspective shows an opportunity to share the BES unit without any negative effects. Whether the system can handle a shared BES unit operated and controlled by the Aggregator and under what conditions is however still unclear. The following section therefore discusses effects of sharing the BES unit between the end-user and the Aggregator in the selected case study by formulating an answer to the second sub-question:

How many PV-systems can be added to the LV distribution grid without jeopardizing the Aggregator's business case?

In order to systematically formulate an answer, the chapter is organized as follows. Section 6.1 first discusses the sharing mechanism in more detail, followed by the reference case and the experimental set-up. Subsequently, section 6.2 and 6.3 discuss the results of the grid optimization for the two most important experimental designs, namely with and without sharing the BES unit's power/energy capacity. Finally, an answer to the sub-question is provided in section 6.4 based on the gained insights before continuing to chapter 7 where the DSO perspective is included in the analysis.

6.1 The sharing mechanism

The sharing mechanism refers to the possibility for end-users to share their BES unit with an Aggregator that could use the reserved power/energy capacity for providing services on the wholesale power markets. Figure 36 visualizes this mechanism to show what exactly happens to the power capacity of the BES unit in case it is shared between two entities.

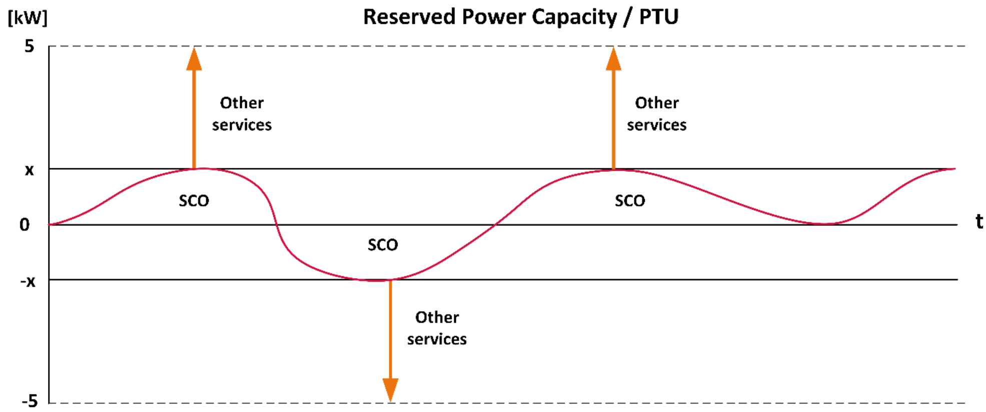

Figure 37: Potential Distribution of BES unit Power Output

The red line shows the potential power output utilized for SCO, while the orange arrows indicate the reserved power capacity that can be summoned by the Aggregator. The black lines at x and –x hence represent the bandwidth for end-users to use the BES unit for SCO. Section 6.1.1 discusses the reference case regarding the Aggregator's perspective and elaborates on the assumed values for x and –x in the remainder of this research.

6.1.1 Reference Case Aggregator Analysis

This section discusses the scenario that is referred to as the reference case to analyze the Aggregator's perspective, and elaborates on the method in terms of implications as compared with the end-user's perspective analysis. Subsequently, the experimental design is discussed in section 6.1.2.

6.1.1.1 PV penetration rate in Kijkduin

The LV distribution grid studied is Kijkduin as is previously discussed in the network configuration section 4.2.2. To repeat briefly, the neighborhood of Kijkduin just outside of The Hague is considered a green urban living environment that primarily consist of 111 large detached houses connected to a 196 [kW] substation. It is selected because it allows for significant growth regarding PV systems and the corresponding potential growth of installed residential BES units. The number of installed PV systems in 2015 was 17, corresponding with a PV penetration rate of 15% (Rijkswaterstaat, 2015).

Table 7 shows the parameters implemented in the Linny-R tool for the reference case including comments on how the parameters are implemented as aggregated values, followed by the plotted Linny-R output shown in figure 38 and 39. As explained in section 5.2.3, the Linny-R tool aims to minimize the total system costs for one full day under the assumption of perfect information for the next day. The difference is found in the interpretation of the results, since the parameters and data input are aggregated to represent the entire LV distribution grid of Kijkduin. This allows analyzing the system from the Aggregator's perspective.

General			
Timeframe: 35136 PTU's in 2016			
Grid Parameters	**Value**	**Unit**	**Comment**
Number of Households	111	[#]	
PV Penetration Rate	15	[%]	
BES Unit Penetration Rate	0	[%]	
Max Substation Capacity	49 (=196 kW]	[kWh/PTU]	
End-user Parameters	**Value**	**Unit**	**Comment**
AEC-profile	5015	[kWh/year]	Implemented as 5015 · 111
Retail price of electricity	0,2	[€/kWh]	Fixed value for each PTU
Wholesale price of electricity	0,03	[€/kWh]	Fixed value for each PTU
PV-system Capacity	5	[kWp]	Implemented as 5 · 111 · 15% PV Rate
PV Inverter efficiency	98	[%]	
BES Unit Energy Capacity	13,5	[kWh]	Implemented as 13,5 · 111 · 0% BES Rate
BES Unit Power Capacity	1.25 (=5 kW)	[kWh/PTU]	Implemented as 1,25 · 111 · 0% BES Rate
BES Unit Inverter Efficiency	90	[%]	
Initial State-of-Charge	50	[%]	Implemented as 13,5 · 111 · 0% · 50%
Self-discharge Rate	2,30533E-05	[kWh/PTU]	Fixed value for each PTU
Solver Settings			
Optimize 96 PTUs at a time from 1 to 35136 with a look-ahead period of 96 days			

Table 7: Parameter settings Reference Case Aggregator perspective

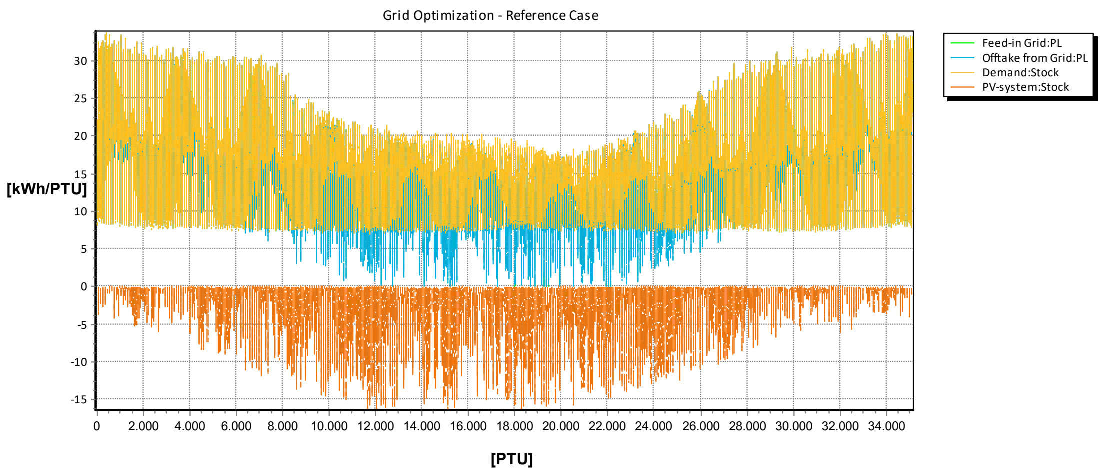

Figure 38: Linny-R simulation output Reference Case Aggregator Perspective

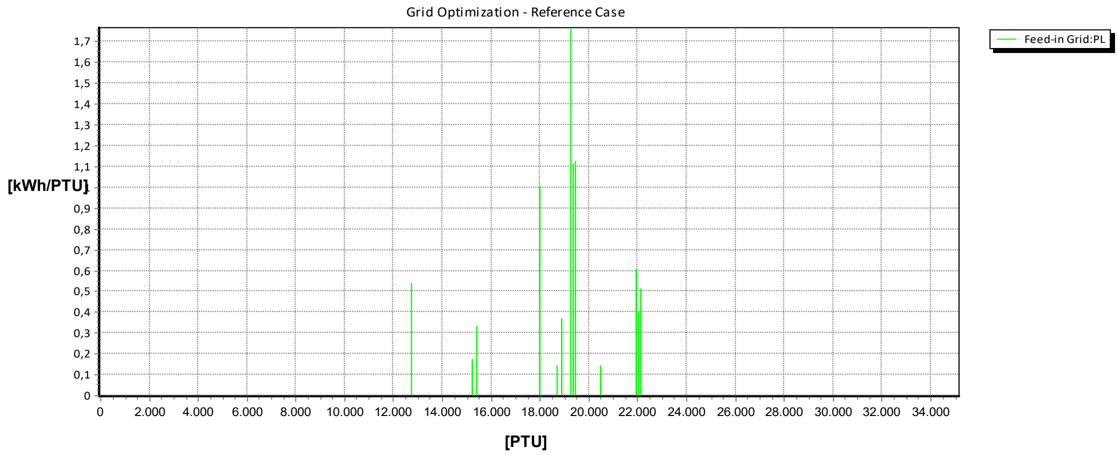

Figure 39: Linny-R simulation output Reference Case Aggregator Perspective Zoomed in at Feed-in Process

The graphs show that only a very small amount of power, 0,05% of total PV production to be precise, is fed into the grid (in green). Notice that feeding in for this grid optimization refers to the power fed into the MV transmission grid. It thus represents the power flow at the LV substation, which for now is the only conclusion that could be drawn from these results. The next section explains why the output indicators as calculated in chapter 5 cannot be calculated based in this scenario.

6.1.1.2 Optimization implications

Section 4.3.3.2 discussed that the Aggregator's perspective is analyzed by means of the same Linny-R model as used for the end-user's perspective. It elaborates on the modelling choice to aggregate the demand and PV profiles into single parameters, therewith allowing power flow analysis on the LV substation level, but excluding the possibility to calculate SS and SC ratios for individual end-users.

The Grid SC ratio can however be calculated when aggregated over all end-users, since it is energy related as compared with the SS ratio from an economic perspective. It provides an indication of the level of grid independence from a system perspective using the same equation as used for individual end-users. This would result in a SC ratio of 98% when applied to the reference case scenario even though the power fed into the grid was only 0,05%. Note that it is theoretically not possible to achieve a SC ratio of 100% due to the definition used in this research that incorporates the inverter losses of the PV-system.

Nevertheless, the focus of this research is to study the value that residential BES units may create, while avoiding congestions in the LV distribution grid by means of aggregation. The next section therefore describes the experimental design to analyze potential congestion issues at the LV substation with the assumption that the Aggregator controls all available BES unit power/energy capacity.

6.1.2 Experimental Design

This section elaborates on the experimental set-up to simulate the LV distribution grid of Kijkduin across various scenarios. It is designed to systematically analyze the Aggregator's perspective as well as the DSO's perspective because both perspectives depend on the behavior of the LV distribution grid as a whole. The two leading dimensions (i.e. design variables) are therefore related to the sharing mechanism and the physical conditions of the grid.

The first design variable follows from the sharing mechanism discussed in section 6.1. The BES units can either be shared with an Aggregator for PCR services or be utilized only for the purpose of SCO. PCR services are not included in the Linny-R model, but analyzed by restricting the BES unit's power and energy capacity to 1 [kW] and 11,5 [kWh] respectively, followed by adding the expected PCR power based on historical probability distribution to the simulated model output. Thus, the Linny-R model provides the expected minimum power flow at the LV substation, which is then recalculated by adding the estimated power flow as a result of PCR services.

The other leading design variable follows from the physical conditions of the LV distribution grid. By not physically constraining the LV substation in the first part of the experimentation phase, it is possible to analyze the opportunities and corresponding potential congestions. The system would behave according to its economic optimum representing the self-interested Aggregator and end-users.

Each experiment that indicates potential congestions in the system is subsequently optimized under stricter grid constraints that represent the LV substation's maximum capacity in the second set of experiments. As a result, it shows the possibility to reduce the congestions and at what costs, or in other words, at what level of curtailment. The first and second set of experiments together aim to answer second sub-question of this research.

Lastly, the design variables representing different economic developments consist of the PV and BES unit penetration rates of the grid, being 15% and 0% respectively in the reference case scenario. In order to get a comprehensive understanding and analyze the conditions under which BES units can reduce congestion issues, the following values are selected. The PV penetration rate varies from 0% to 100% with discrete steps of 20%. The BES penetration rate varies the same, although it is assumed that only end-users with already installed PV-systems also install a BES unit. Figure 39 visualizes the experimental design discussed in this section.

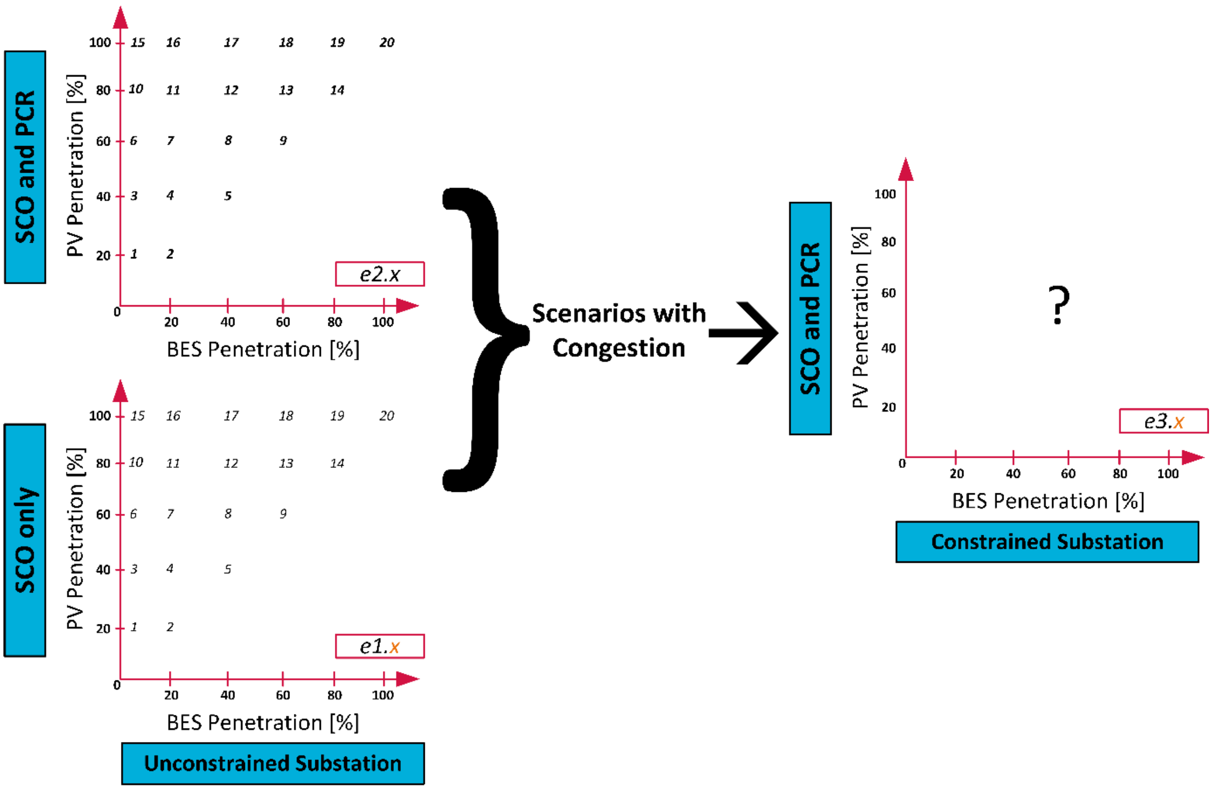

Figure 40: Experimental Design Aggregator Perspective Simulations

6.2 First set of experiments: Self-Consumption Optimization

This section elaborates on the results of the first set of experiments in which the BES units are only utilized for SCO in an unconstrained LV distribution grid under various economic developments (i.e. PV and BES unit penetration rates). The objective is to analyze under which conditions potential congestion issues at the LV substation occur by using the developed Linny-R tool. The same model, optimization objective, and degrees of freedom as discussed in table 7 apply for the following analysis. Yet, the parameter settings differ per experiment according to the experimental design, primarily the amount of PV-system and BES unit penetration rates in the distribution grid.

Section 6.2.1 discusses the peak power flow at the LV substation to identify potential congestion issues, followed by an analysis of the output indicators FSO_w and $FSO^{TotalWeeks}$ in section 6.2.2 to identify the order of magnitude of the problems in each scenario.

6.2.1 Expected congestions at LV substation

Figure 41 shows the maximum feed-in power flow, which corresponds with the power flow at the LV substation, for each defined PV and BES unit penetration rates. Note that all bars showing a value of zero do not imply the absence of power flow at the LV substation. When no feed-in peak occurs, the power flow is equal to the maximum aggregated power flow demanded by all households connected to the grid. This is equal to 135 [kW] for each of the scenarios since each simulation run uses the same demand profiles. However, these values are excluded to clearly show which scenarios are simulated in Linny-R and which are not.

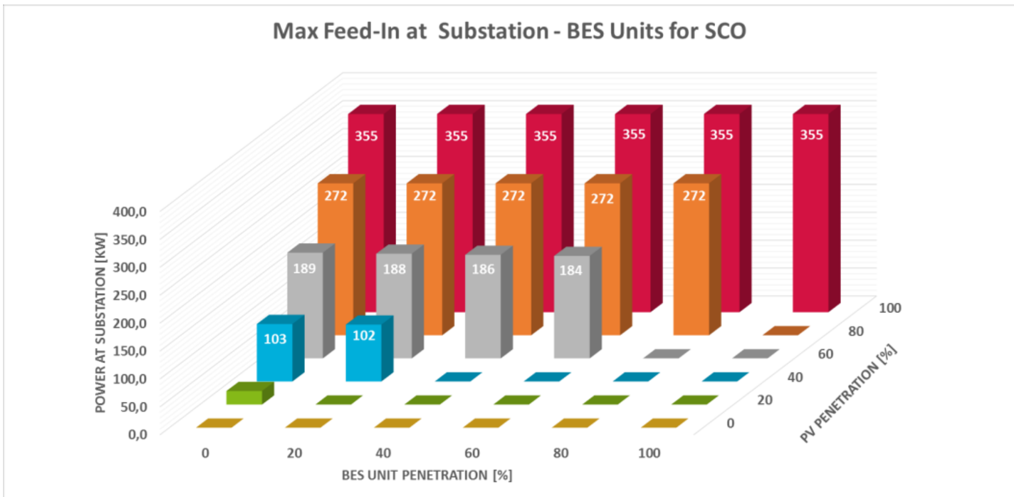

Figure 41: Linny-R Simulation Output - First Set of Experiments (a)

Furthermore, the orange and red bars in figure 41 exceed the maximum capacity of the substation of 196 [kW] with 72 [kW] and 155 [kW] respectively. Figure 42 shows the Linny-R model output of a scenario with 80% PV penetration and 20% BES unit penetration to exemplify the origin of the results. The highest peak in green therefore relates to the orange bar in figure 40. Note that the y-axis values are shown in [kWh], explaining the relation between the 68 [kWh] and 272 [kW].

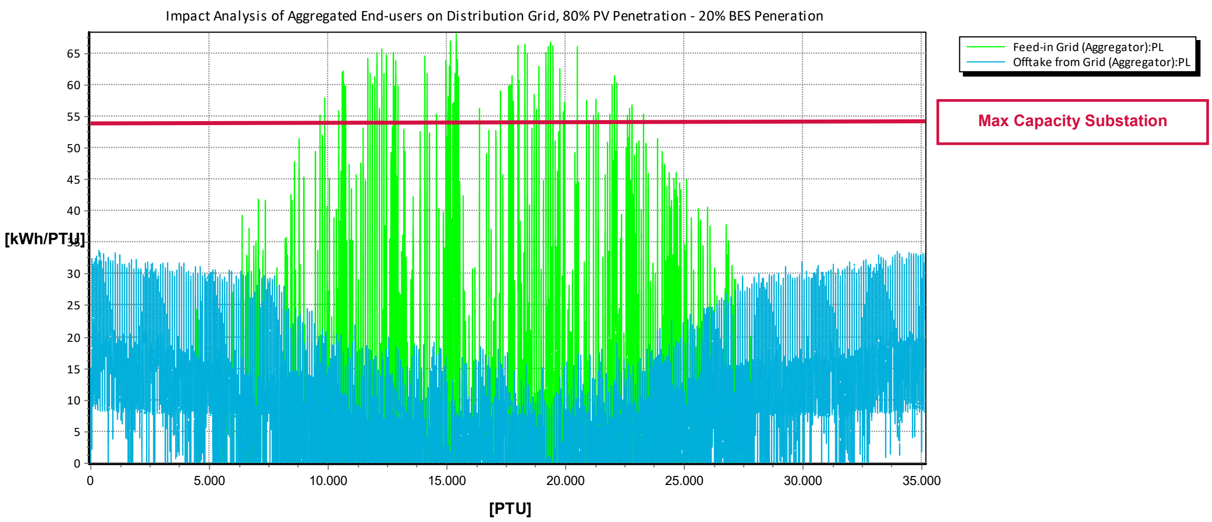

Figure 42: Linny-R Simulation Output - First Set of Experiment (b)

Adding extra BES unit capacity to the grid under these PV penetration levels does not reduce the maximum peaks at the LV substation. This differs with lower PV penetration rates, for example at 60%. The peaks in the system are reduced by 5 [kW] when adding a BES unit to each PV-system. Although no congestions are expected to occur under that scenario, it does demonstrate the potential to reduce peak loads in the system by BES units. This is even further supported by the 40% PV penetration rate scenarios. Increasing the BES units from 20% to 40% reduces the peak with 102 [kW] to 0 [kW].

To conclude, the maximum allowed PV penetration rate on this grid to avoid congestions is approximately 60%. Adding extra BES units may increase this value although it is unclear to what extent they can actually reduce peaks at the LV substation at higher PV penetration rates.

6.2.2 Other output indicators

The maximum peak at the LV substation caused by PV systems provides an indication of expected PTUs with congestion. However, most LV substations are resistant to overloads to a certain extent, probably to the detriment of the life expectancy (Fulchiron, 2011). Therefore, the output indicators FSO_w and $FSO^{TotalWeeks}$ are analyzed in this section to determine the order of magnitude of the expected congestion problems. The former shows the frequency in PTUs at which the power flow at the LV substation exceeds its maximum capacity, while the latter shows the number of weeks that any congestions occur at all. Furthermore, the output indicator Grid SC Ratio as discussed 6.1.1.2 is also included for model verification purposes. Table 8 provides an overview of all important output indicators that were simulated by means of the Linny-R model for the first set of experiments $e1.x$.

LinnyR Output - Unconstrained Grid - BES Unit for SCO						
Scenario	Installed PV [%]	Installed BES [%]	Max Feed-in [kW]	Freq. Sub-station Overloads [#]	Freq. Congestion Weeks [#]	Grid SC Ratio [%]
e1.1	20	0	24	0	0	95,9
e1.2	20	20	0	0	0	97,7
e1.3	40	0	103	0	0	76,1
e1.4	40	20	102	0	0	91,6
e1.5	40	40	0	0	0	94,0
e1.6	60	0	189	0	0	60,5
e1.7	60	20	187	0	0	77,2
e1.8	60	40	186	0	0	86,4
e1.9	60	60	184	0	0	88,6
e1.10	80	0	272	838	23	50,6
e1.11	80	20	272	430	22	65,6
e1.12	80	40	272	335	21	75,8
e1.13	80	60	272	317	17	79,0
e1.14	80	80	272	338	16	80,0
e1.15	100	0	355	1947	30	43,4
e1.16	100	20	355	1126	30	56,7
e1.17	100	40	355	933	30	66,5
e1.18	100	60	355	953	24	69,8
e1.19	100	80	355	955	23	70,7
e1.20	100	100	355	947	23	70,8

Table 8: Output Indicators per Scenario - First Set of Experiments

Experiments e1.1 to e1.9 show no overloads at the LV substation in line with the results discussed in the previous section. However, the Grid SC Ratio shows significant improvements when adding BES units to the system. While the maximum peak in the 60% PV penetration scenario can only be reduced with 5 [kW], the self-sufficiency of the grid increases with from 60,5% to 88,6% in case a BES unit is installed next to each PV-system.

Similar results are visible at higher levels of PV penetration, although the most significant improvements are made when increasing the BES penetration rate to 40%. Increasing the BES penetration rate even further show diminishing returns due to the phenomena discussed in 5.2.2 through hypothesis 2. The BES unit does not charge more power than required in the next 96 PTUs, because Linny-R minimizes the total cost. Less power stored increases the need to extract power from the grid, directly affecting the Grid SC Ratio. Once again, the Grid SC Ratio therefore only provides an indication of grid independence. Better results may be possible when optimizing for the purpose of maximizing self-consumption.

The last two columns in table 8 show the output indicators FSO_w and $FSO^{TotalWeeks}$. Starting with the former, the number of PTUs with congestion decrease with 60% from 838 to 338 when adding a BES unit next to each PV-system. Similarly in a scenario with 100% PV penetration, the number of PTUs reduce with approximately 51% from 1947 to 947.

Also the number of weeks that face PTUs with congestion at all show significant improvements when installing BES units in addition to the PV-system. Both the 80% and 100% PV penetration scenarios show an improvement of 7 weeks when adding BES units to the system. Figure 43 zooms in on the congestion weeks at 80% PV penetration to show the distribution of LV substation overloads. Note that the figure only shows week 13 to 37 since this are the only weeks with congestion.

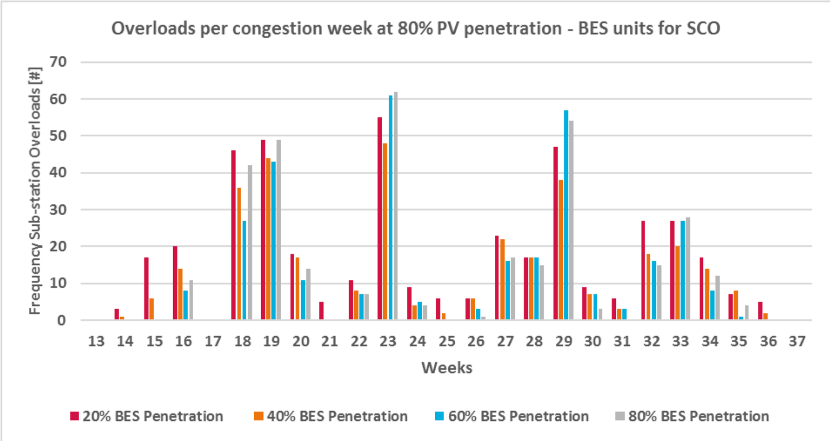

Figure 43: Expected Congestions Weeks and Frequency of Congestions - First Set of Experiments

Note that adding more BES unit capacity does not automatically result in fewer peaks during a specific week, for example week 23. The total peaks do however decrease as discussed earlier using table 8. The reason for this is found in the optimization set-up. The optimization tries to minimize costs while not considering any maximum LV substation power constraint. Thus, the system even tends to maximize the power fed into the grid as long as sufficient power is stored for the next day, regardless of the BES unit penetration.

To conclude, congestions start to occur with a PV penetration rate of 70-80% distributed between week 13 and 37 of the year. The frequency of congestions and the corresponding number of weeks could be reduced by installing BES units to each PV-system, although the results also show that adding BES units to the system does not necessarily reduce the amount of congestions for a particular week. The optimization simply does not consider the LV substation congestion while it minimizes total system costs. Whether these results hold up if the BES unit is partly utilized by the Aggregator for PCR services is discussed in the next section.

6.3 Second set of experiments: Sharing BES unit capacity

This section elaborates on the experimental results of the second set of experiments in which the BES units are simultaneously utilized by the Aggregator for SCO and PCR. The grid is once again unconstrained in order to compare the results with the experiments discussed in the previous section. The parameters representing the power and energy capacity of the BES units are set to 1 [kW] and 10,5 [kWh] respectively, while all others remain the same as discussed in section 6.2.

First, the maximum feed-in from PV is discussed, followed by the other output indicators. The expected PCR power activation is determined, succeeded by an analysis of the newly computed output indicators (i.e. Linny-R output with expected PCR activation) according to the same structure as section 6.2.

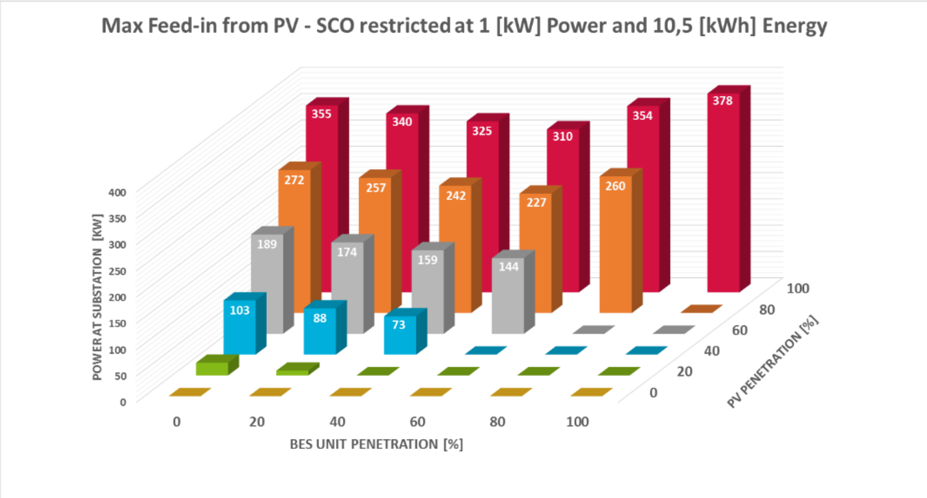

Figure 44: Linny-R Simulation Output - Second Set of Experiments

Figure 44 shows the maximum feed-in power flow, which represents the power flow at the LV substation, for each defined PV and BES unit penetration rate. The critical PV penetration level for congestion to occur is approximately 60%. It is clearly visible that BES units at this PV penetration level or lower are able to reduce the peaks, therewith benefitting the system. For example, adding BES units at 60% PV penetration level could reduce the peak with 45 [kW] from 189 [kW] to 144 [kW]. This can be explained via the restricted power capacity of the BES units which ensure that exceeding the maximum energy capacity requires a longer period of time. The BES unit is therefore not yet fully charged in cases when serious PV-system surpluses occur, allowing the BES unit to charge and therewith reduce power fed into the grid.

Note that the maximum feed-in increases when adding more BES units to the system in the scenarios with an 80% and 100% PV penetration rate. This can be explained by the unique coincidence of the PV production profiles, which are equal in each scenario, and the SOC of the BES units. Even though a single observation of the maximum peak increased, the frequency of overloads deceased as shown in appendix C.

Finally, the results provided in figure 44 only show the expected congestions as a result of SCO without considering additional PCR activation. The added power flows caused by PCR activation still have to be added in order to estimate the congestions that occur when the BES unit is shared between the end-user and Aggregator. The next section therefore discusses how the activation of PCR power is included in the analysis.

6.3.1 Activation of Primary Control Reserve Services

The PCR is automatically activated within the entire continental European synchronous control area when the frequency deviates more than +/- 0.02 Hz from the nominal value as discussed in the system analysis. Figure 45 shows a histogram of the maximum and minimum frequency deviation that occurs in each PTU during a typical summer week, which was found to be similar for a typical winter week. The data is obtained from Regelleistung, the cooperation partner for PCR tenders of TenneT, with a resolution of one second.

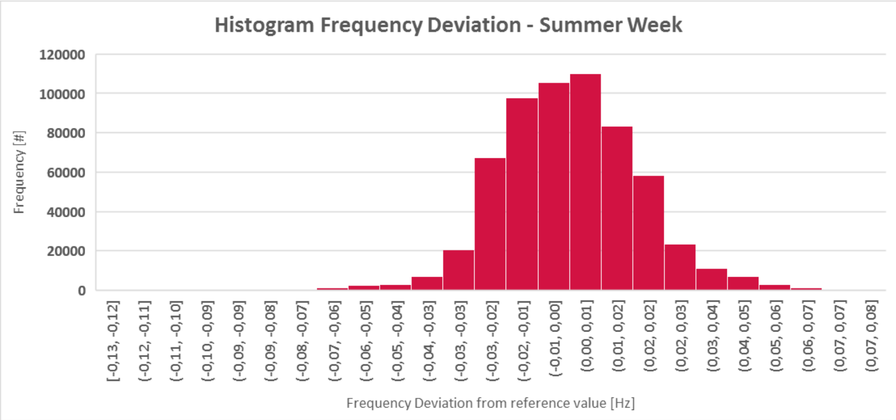

Figure 45: Probability Distribution Grid Frequency Deviation

A negative frequency deviation requires the BES unit to charge, where a positive deviation requires discharging. The required power to charge depends on the contracted PCR power. Simple statistical analysis shows an average μ equal to 0, and a standard deviation equal to 0,01867. Table 9 shows the maximum expected PCR activation based on these values, under the assumption that the data set is characterized by a normal distribution. The required charging/discharging power is calculated according to (21), where the value 0,2 represents the maximum deviation that must be corrected by PCR services. The calculated expected PCR activation values are used in the next section to expand the congestion analysis for the second set of experiments.

$$Required\ PCR\ Power\ [kW] = \frac{Frequency\ Deviation\ [Hz]}{0{,}2\ [Hz]} * Contracted\ PCR\ [kW] \tag{21}$$

Maximum expected PCR Activation per scenario					
BES Unit Penetration [%]	20	40	60	80	100
PCR available [kW]	88	176	268	356	444
μ +/- 2σ	Likely Scenario				
Required Charging [kW]	15,9	31,8	48,5	64,4	80,3
Required Discharging [kW]	-16,9	-33,9	-51,6	-68,5	-85,4
μ +/- 3σ	Very Likely Scenario				
Required Charging [kW]	24,1	48,3	73,5	97,6	121,8
Required Discharging [kW]	-25,1	-50,3	-76,6	-101,7	-126,9

Table 9: Expected PCR Activation per BES unit penetration rate

6.3.2 Other output indicators

Table 10 provides an overview of the computed output indicators that were simulated by means of the Linny-R model for the second set of experiments $e2.x$, and corrected by the maximum expected PCR activation as shown in table 9. It shows that the maximum feed-in peaks which cause the LV substation to overload occur at a PV penetration rate of 60% as compared with 80% in the first set of experiments. This is only true for the scenario (e2.9) that included a BES unit next to each PV-system. Note that the congestion in this scenario corresponds to an overload of 2 [kW] during only 10 PTUs, meaning that in reality this would only happen if the requested PCR power is summoned in the exact same PTU as the peak load caused by the aggregated PV systems. Hence, scenario e2.9 is not considered a congestion scenario to study in more detail in the next chapter.

LinnyR Output - Unconstrained Grid - BES Unit restricted at 1 kW SCO ***with*** PCR Activation						
Scenario	Installed PV [%]	Installed BES [%]	Max Feed-in [kW]	Freq. Sub-station Overloads [#]	Freq. Congestion weeks [#]	Grid SC Ratio [%]
e2.1	20	0	24	0	0	95,9
e2.2	20	20	28	0	0	97,7
e2.3	40	0	103	0	0	76,1
e2.4	40	20	107	0	0	84,4
e2.5	40	40	110	0	0	89,8
e2.6	60	0	189	0	0	60,5
e2.7	60	20	193	0	0	69,3
e2.8	60	40	197	0	0	76,1
e2.9	60	60	200	10	5	81,5
e2.10	80	0	272	838	23	50,6
e2.11	80	20	276	901	24	58,8
e2.12	80	40	280	961	25	65,6
e2.13	80	60	283	1013	25	71,4
e2.14	80	80	335	1119	25	75,5
e2.15	100	0	355	1947	30	43,4
e2.16	100	20	359	2042	30	51,0
e2.17	100	40	362	2138	30	57,5
e2.18	100	60	366	2238	30	62,9
e2.19	100	80	327	2440	30	66,4
e2.20	100	100	472	2767	31	68,3

Table 10: Linny-R Output per Scenario - Second Set of Experiments (b)

Experiments that are considered congestion scenarios are those with a PV penetration rate larger than 60%. The number of PTUs with congestion and the number of so-called congestion weeks displayed in table 10 show different results compared with the first set of experiments discussed in section 6.2.2. Starting with the former, the PTUs with congestion increase with 33,5% from 838 to 1119 when adding a BES unit next to each PV-system. Similarly, in a scenario with 100% PV penetration, the number of PTUs with congestion increase with 42,1% from 1947 to 2767.

The related congestion weeks increase with 2 and 1 week for the 80% PV penetration and 100% PV penetration scenarios respectively. Figure 46 zooms in on the congestions per week at an 80% PV penetration rate to show the distribution of congestions. Note that the figure only shows week 12 to 35 since this are the only weeks with congestion.

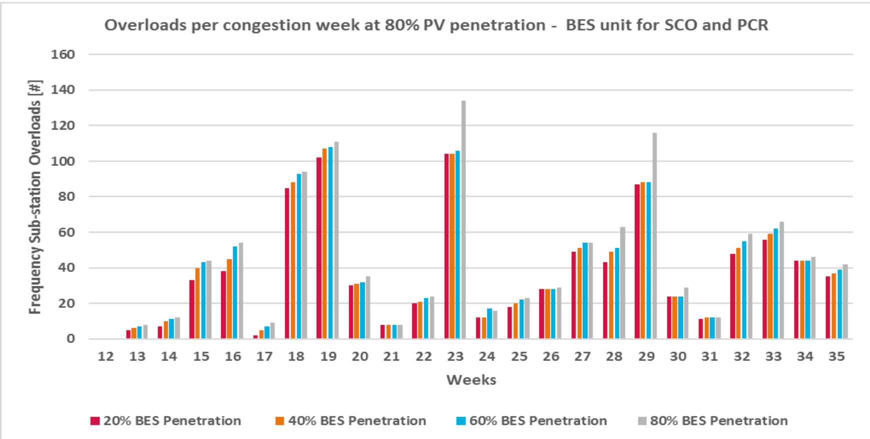

Figure 46: Expected Congestions Weeks and Frequency of Congestions - Second Set of Experiments

The results are a lot more consistent as compared with the first set of experiments discussed in 6.2.2. This can be explained by the addition of PCR power activation to the model outputs, which scales linearly with the BES penetration rate. Hence, adding more BES units to the system results in more congestions in almost each week as shown in figure 46, which implies that the PCR activation is the determinant factor causing the increasing congestion problems.

To sum up, congestions start to occur at a PV penetration rate larger than 60%. The frequency of individual congestions with the addition of PCR services increases, although the number of congestion weeks remains approximately the same both compared with the utilization of only SCO. It shows the inability of BES units to reduce congestions when they are shared between end-users and the Aggregator. The distribution of overloads per week supports this argument since it implies the PCR power as the determinant factor causing congestion problems. Nonetheless, the Aggregator could be able to reduce the congestions and corresponding weeks, while still offering PCR services during the majority of the year in multiple ways.

The first alternative would be to exclude some BES units from their PCR obligations in case of overcapacity in the aggregated BES unit pool. In particular during weeks with very few congestions, for example week 17 shown in figure 45. The costs of this alternative would be equal to the sum of load flexibility premiums paid to the end-users ensuring the overcapacity. Since it is difficult to predict the congestion weeks in terms of frequency of individual congestions that specifically determine the required energy capacity and the magnitude of congestions that determine the required power capacity, it is decided not to analyze this alternative in the remainder of this study.

A second alternative is found in the possibility to withdraw from PCR services on a weekly basis, making additional power and energy capacity available to reduce congestions in those weeks. Whether that would be sensible from an economic perspective depends on the remuneration provided by the congestion owner, in this case the DSO. As argued in 3.4.3.3, the remuneration for such services should be proportional to the Aggregator's opportunity costs for not delivering PCR services, corresponding to 30.000 [€/year] based on 12 congestion weeks with at least 40 congestions or more. The costs of this alternative are significantly higher than the costs of grid reinforcement as will be discussed in section 7.1.2 and is therefore also not studied in the remainder of this research.

A third and final alternative considered in this research is the active curtailment of power generated by the PV-systems of end-users. Costs of this alternative are found in compensating end-users for their opportunity losses as a result of curtailment. The developed Linny-R model allows simulating this alternative by including a hard constraint for the connection capacity, and therewith analyze the total curtailment required to avoid congestions at the LV substation. This scenario is represented by the third set of experiments and will be discussed in chapter 7, since it closely relates to the DSO perspective.

6.4 Conclusions on sharing the BES unit between end-users and the Aggregator

Chapter 6 discussed the Aggregator's perspective when residential BES units are shared between end-users and an Aggregator by analyzing the output indicators related to LV substation congestions simulated by the Linny-R model across various scenarios. Based on the gained insights, this section aims to formulate an answer to the following sub-question.

How many PV-systems can be added to the LV distribution grid without jeopardizing the Aggregator's business case?

Section 6.1 briefly discussed the sharing mechanism, presented the reference case, and discussed the experimental design to systematically analyze the system when it is optimized from the Aggregator's perspective. The most important design variable, defining the experiments discussed in this chapter, is given by the degree of sharing the BES unit between the end-users and the Aggregator.

The output indicators discussed in section 6.2 show the results of the Linny-R model simulations for the first set of experiments, representing the utilization of BES units only for the purpose of SCO. Congestions start to occur with a PV penetration rate of 70-80% between week 13 and 37 of the year. BES units are able to reduce the congestions, although not necessarily proportional to the additional BES units due to the experimental set-up of not including a grid constraint.

Section 6.3 discussed the output indicators for the second set of experiments, representing the utilization of BES units for SCO and PCR services. For those scenarios, congestions start to occur at a slightly smaller PV penetration than the first experiments – at approximately 60%. The results show that the BES units are unable to reduce the frequency of individual congestions, although the number of congestion weeks remains roughly the same. PCR power activation is expected to be the determinant factor explaining this inability. Nonetheless, three alternatives are identified that allow the Aggregator to reduce congestions while still offering PCR services during the majority of the year.

Based on these insights it is concluded that a PV penetration rate of 60% is the threshold value before the business case of the Aggregator becomes jeopardized. The number of expected congestions at higher PV penetration levels increases, yet the number of so-called congestion weeks remains roughly the same. Since the Aggregator is critical to ensure the economic viability of the BES units in the first place, the next chapter aims to study the costs of reducing the congestions when the BES units are also utilized for this particular purpose.

7 Value from the DSO perspective

The previous chapters analyzed the potential value of residential BES units from both the end-user's and the Aggregator's perspective. They showed the need for an Aggregator to ensure a profitable investment on the one hand, but also the negative impact of the aggregated BES units on the LV substation on the other hand. The DSO is in principle responsible to provide reliable distribution services to the end-users, and is therefore the problem owner of the expected congestions. Despite the Aggregator being the main cause of the problems, it is expected that she may still create value for DSOs, since the congestions occur only temporarily during the year. The following section therefore discusses the costs of alternative solutions to reduce congestions, therewith formulating an answer to the third sub-question:

What are the costs of congestion management services provided by the Aggregator?

In order to systematically formulate an answer, the chapter is organized as follows. Section 7.1 discusses the costs of the most straightforward method to avoid congestions, which is grid reinforcements. Subsequently, section 7.2 briefly describes the third and final set of experiments simulated by means of the Linny-R tool, followed by a discussion of the results. The section represents the Aggregator alternative for congestion management. Finally, an answer to the sub-question is provided in section 7.3 before evaluating the welfare indicators associated with each congestion management alternative in the next chapter.

7.1 The costs of grid reinforcements

The costs of grid reinforcement are assumed to primarily consist of the costs related to upgrading the transformer capacity, and additional costs of underground conductors. A study by Gonzalez-Sotres, Mateo Domingo, Sanchez-Miralles, & Alvar Miro (2013) proposed a method to optimize the location, size, and supply area of MV/LV transformer substations using realistic key figures for the costs of various types of distribution grid assets. Those same key figures are used in the next two sections to assess the costs of grid reinforcements for the LV distribution grid of Kijkduin. Section 7.1.1 determines the future grid requirements, followed by the discounted yearly costs of grid reinforcements by means of the NPV method.

7.1.1 Future grid requirements

Starting with the transformer capacity, the maximum peak expected to occur in a scenario with 70-80% PV penetration is approximately 335 [kW] implying the need to at least double the LV substation capacity from 192 [kW] to 384 [kW]. The corresponding investment costs (IC) are 18.000 [€] with an additional 1200 [€] for preventive maintenance costs (PMC), and 6800 [€] for corrective maintenance costs (CMC)(Gonzalez-Sotres et al., 2013). It is assumed that the DSO has PMC each year, while the CMC is occurs only once every 5 years except during the last year of its lifetime. The lifetime expectancy of the LV substation is assumed to be 20, 30, and 40 years representing a low, medium and high scenario respectively (Stedin, 2014).

The second factor strongly affecting the costs of grid reinforcement is found to be upgrading the underground conductors, usually measured in [€/km]. The IC are 12.000 [€/km] with an additional PMC of 5,4 [€/km], and CMC of 610 [€/km]. Unfortunately, no data that indicates the length of underground conductors in Kijkduin is available, yet it can be reasonably estimated by means of Google Maps, since the location of the LV distribution grid is known. The length of underground conductors is therefore estimated to be approximately 4 [km]. However, the values are again assumed for a low, medium and high scenario corresponding to 3, 4, and 5 [km] respectively. The lifetime expectancy is similar as the LV substation. Table 11 provides an overview of the costs in each scenario.

Total Costs of Grid Reinforcements			
Expected Conductor Length [km]	Lifetime Expectancy [years]		
	20	30	40
3	€ 104.214	€ 133.636	€ 163.058
4	€ 118.152	€ 148.848	€ 179.544
5	€ 132.090	€ 164.060	€ 196.030

Table 11: Estimated Costs of Grid Reinforcements

7.1.2 The grid reinforcements costs for end-users

The NPV method is used to calculate the required future cash-in flows that ensure a viable investment (i.e. a positive NPV) for the DSO. These future cash-in flows are assumed to be equally distributed over the lifetime of the asset, and charged to the end-users connected to the LV distribution grid of in Kijkduin. The discount rate is assumed to be 5%, representing the regulated annual rate of return that DSOs are allowed to aim for. Table 12 shows the calculated future cash-in flows for each of the assumed scenarios on the left side, while the values are converted to the yearly costs per end-user connected to Kijkduin on the right side of the table 12.

The required cash-in flows range from 5900 to 9000 [€/year], meaning that the alternative to compensate the Aggregator for PCR withdrawal is considered inefficient, and will therefore not be studied in the remainder of this study. Converted to the yearly costs per end-user, the values range from 53-81 [€/year] depending on the scenario.

The orange values are highlighted, since those are used for further analysis in the next chapter. Therefore, figure 47 provides the NPV over time to clearly visualize the origin of the calculated values, where the small drops represent the previously discussed PMC and CMC. The total investment costs are recouped after exactly 30 years, indicated by a NPV of zero. This assumes that the assets retain no residual value, and the cash-in flow is 7049 [€/year].

Expected Conductor Length [km]	Required Cash-in Flows for positive NPV			Yearly Costs per end-user		
	Lifetime Expectancy [years]			Lifetime Expectancy [years]		
	20	30	40	20	30	40
3	€ 6.851	€ 6.161	€ 5.854	€ 62	€ 56	€ 53
4	€ 7.911	€ 7.049	€ 6.664	€ 71	€ 64	€ 60
5	€ 8.971	€ 7.936	€ 7.474	€ 81	€ 71	€ 67

Table 12: Estimated Yearly Costs of Congestion Management based on NPV method

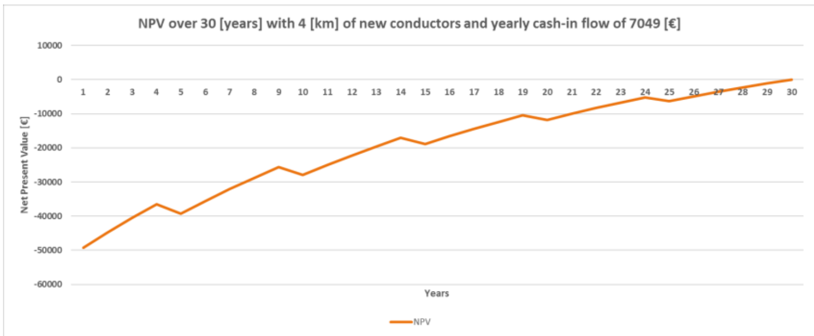

Figure 47: NPV over time of Grid Reinforcements

7.2 Third set of experiments: The Aggregator alternative

The other alternative, next to reinforcing the grid assets, is referred to as the Aggregator alternative. In this alternative, the Aggregator optimally dispatches the residential BES units and curtails PV power if necessary in order to avoid congestions, while possessing sufficient information about the LV distribution grid.

The experimental design as discussed in section 6.1.2 identifies a third set of experiments to be simulated by means of the Linny-R model. Similarly as for the second set of experiments $e2.x$, they represent the distribution grid with BES units that are shared between end-users and the Aggregator. The same model, optimization objective, parameters and degrees of freedom as discussed in section 6.3 apply to the analysis of this entire section 7.2. The main difference is however found in the additional constraint to limit the LV substation capacity, therewith forcing the system to modify its charging/discharging behavior, and optionally to curtail PV power if necessary. The value of this parameter setting is corrected by subtracting the expected PCR activation according to table 9 from the reference value representing the maximum capacity of the LV substation.

Figure 48 shows the behavior of the system for a scenario with 80% PV penetration, 40% BES penetration and a maximum LV substation capacity of 146 [kW]. The straight feed-in pattern in green shows the limited LV substation capacity. Power can only be fed into the grid up to 36.5 [kWh/PTU], or 146 [kW], where the remaining surplus is curtailed or charged into the BES units if possible. The BES units' limited power capacity causes the system to curtail as shown in black, even though sufficient energy capacity is available to store surplus PV power.

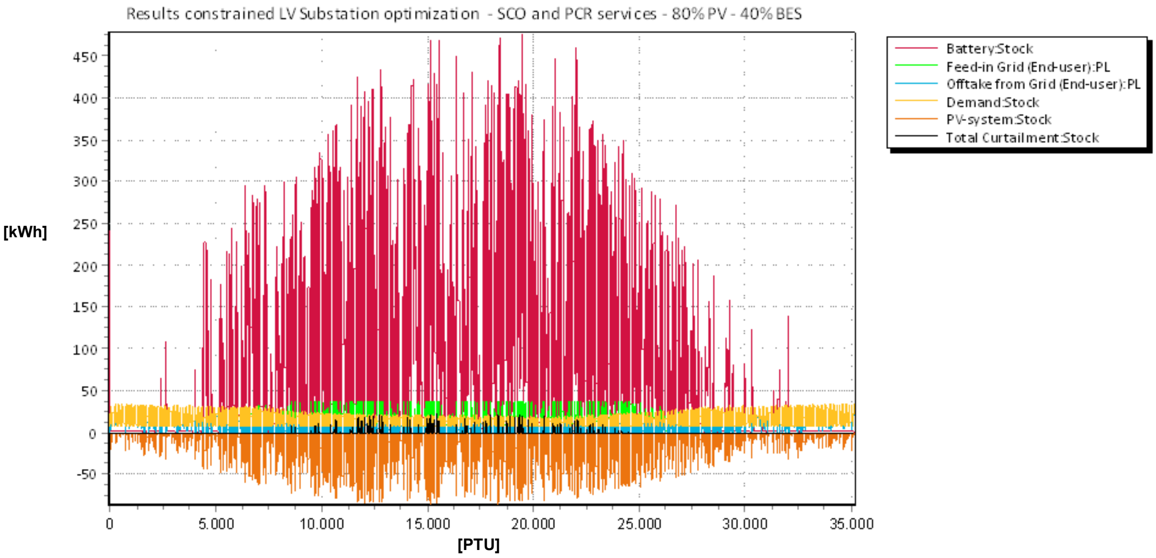

Figure 48: Linny-R Simulation Output - Third Set of Experiment

All experiments that revealed congestions as discussed in section 6.3 are eligible for this analysis. Hence, we turn to the scenarios with 80% and 100% PV penetration for each BES unit penetration rate. Table 13 show the results of the third set of experiments with an additional output indicator, 'Energy Curtailment', as a replacement of the frequency of congestions FSO_w and related congestion weeks $FSO^{TotalWeeks}$.

Note that the experiments with a 100% PV penetration rate are not simulated. It is expected that those simulations will not provide any additional insights regarding the costs of energy curtailment. Besides, a 100% PV penetration rate is not very likely to materialize in reality, and will therefore not be considered in the comparison of alternatives discussed in the remainder of this study.

Scenario	Installed PV [%]	Installed BES [%]	LV Substation Capacity [kW]	Max Feed-in [kW]	Grid SC Ratio [%]	Energy Curtailed [kWh]
e3.1	80	0	196	196	50,6	6053
e3.2	80	20	171	171	58,8	6836
e3.3	80	40	146	146	65,6	7700
e3.4	80	60	119	119	71,1	8647
e3.5	80	80	98	98	74,3	8504

Table 13: Output Indicators per Scenario - Third Set of Experiments

First of all, the Feed-in peaks in the system decrease when adding more BES units to the system as a result of the LV Substation Capacity. Furthermore, the energy curtailed increases with 40.5% to 8500 [kWh] when adding a BES unit to each PV-system corresponding to 2.2% of the total PV production in the grid. The reason that the energy curtailed increases with the number of BES units is found in the corresponding LV substation capacity. The small decrease at 80% can be explained by the one-on-one coverage of PV-systems by BES units, even though the LV substation capacity decreases as well. The Grid SC Ratio shows similar results as discussed in section 6.3.2 to verify the behavior of the BES units.

The amount of energy curtailed is considered an opportunity loss for the end-users and therefore represents the costs of the Aggregator alternative. For a scenario with a BES unit next to each PV-system, this would result in a minor 255 [€/year] when valued at the wholesale price of 0,03 [€/kWh].

7.3 Conclusions on the costs of congestion management

Chapter 7 discussed the value of residential BES units from the DSO's perspective by analyzing the costs of two alternative solutions for congestion management. Based on the gained insights, this section aims to formulate an answer to the following sub-question:

What are the costs of congestion management services provided by the Aggregator?

Section 7.1 discussed the most straightforward method to avoid congestions in the LV distribution grid, which is investing in new assets. The scope of new assets is estimated in terms of the required LV substation capacity and length of conductors in [km]. By using key figures, the total costs of grid reinforcements are expected to range from 100.000-200.000 [€] depending on the required conductors and life expectancy of the assets.

The required future cash-in flows to ensure a viable investment for the DSO are calculated by means of the NPV method and range between 5900 and 9000 [€/year] under the assumption that the assets are completely depreciated over the expected life time and an annual return rate of 5%. Converted to the yearly costs per end-user connected to the LV distribution grid, the values range from 53-81 [€/year], again depending on the scenario.

Subsequently, section 7.2 discussed the other alternative for congestion management, where the Aggregator optimally dispatches the residential BES units and curtails PV power if necessary. Model simulations showed that only 2.2% of the total PV production needs to be curtailed in order to satisfy the demand of all end-users when a BES unit is added to each PV-system. The opportunity losses for end-users of 255 [€/year] are considered the costs of the Aggregator alternative, therewith formulating an answer to the sub-question.

It appears that the Aggregator alternative is the cheaper option for congestion management. However, whether value is actually created or only distributed differently is still unclear. The next chapter therefore compares the two alternatives from a system perspective by analyzing the welfare indicators for each actor.

8 Market interactions and discussion

The perspectives discussed in the previous three chapters showed in consecutive order that:

(1) End-users with PV-systems could gain an economic advantage by investing in a residential BES unit as long as additional income streams are generated via the Aggregator

(2) The profitability of the Aggregator's business case becomes jeopardized at a PV penetration rate larger than 60% due to congestion issues, and

(3) The costs of the flexibility services provided by the Aggregator are lower than grid reinforcements as means for congestion management.

Each of these conclusions have been analyzed from a single actor perspective while only considering one other actor, e.g. sharing the BES unit between the Aggregator and end-users. This section therefore aims to incorporate the three different perspectives by analyzing the total system costs for both the grid reinforcement alternative and the Aggregator alternative. The results allow to formulate an answer to the fourth and final sub-question.

To what extent can the Aggregator reduce the total system costs by offering electric flexibility services to the DSO for congestion management?

The chapter is structured by first briefly reviewing the interpretation of system costs in terms of cash flows followed by an assessment for both alternatives of congestion management. Thereafter, the distribution of cash flows within the system are reviewed as they would materialize within the case study of Eneco CrowdNett. Then, a thorough reflection is provided on the results and insights gained through this research. It aims to incorporate the limitations of the selected method, the case study, and model assumptions in order to reflect on the research contribution in terms of usability and applicability. An answer is provided to the last sub-question in section 8.3 taking everything into consideration. Finally, the conclusions are provided in chapter 9 aiming to formulate an answer to the main research question.

8.1 Total system costs

The two alternatives for DSOs to avoid congestions on the LV distribution grid under review are traditional grid reinforcements and shifting peak loads by means of an Aggregator with an additional option to curtail PV surplus. It seems that the costs of the Aggregator alternative to avoid congestions are lower than the costs of grid reinforcements made by the DSO based on the previous chapter, which in both cases are passed on to the end-users via additional grid tariffs. However, the impact of both alternatives on the system as a whole is not assessed yet.

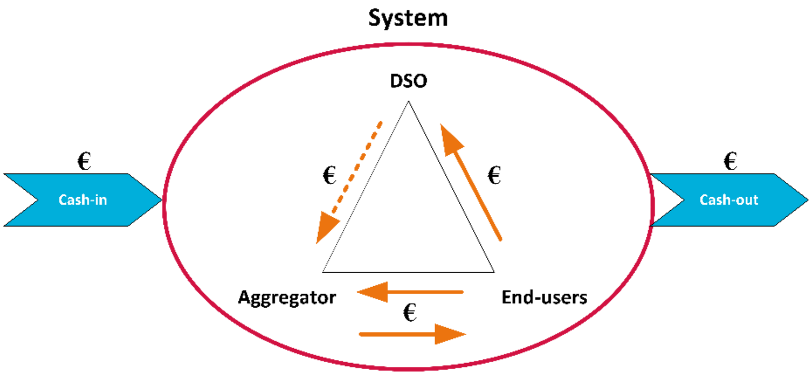

Figure 49: Internal and external cash flows of the system

Figure 49 shows the external cash flows moving in and out of the system (blue arrows), and the internal cash flows within the system (orange arrows). The congested scenario with 80% PV penetration is selected to assess how the different arrows would materialize in both alternatives for congestion management. First, section 8.1.1 discusses the total costs from a system perspective, followed by an assessment of the cash flows from the actor perspectives, represented by the blue and orange arrows in figure 49 respectively.

8.1.1 System perspective

The cash flows entering and leaving the system are primarily determined by the system's interaction with the wholesale power markets, potential asset investments, and tax schemes. For example by extracting power from or feeding power in the MV grids against wholesale prices, investing in a new LV substation, or the payment of energy taxes by end-users to the authorities. Table 14 shows the cash flows entering or leaving the system for each of the two congestion management alternatives, without considering who captures the value in terms of profits or cost reductions. Negative values refer to the cash flows leaving the system, whereas positive values refer to cash flows entering the system. The values for power extracted and power fed in are provided by the Linny-R tool simulations in a scenario with 80% PV penetration.

For a fair comparison with the yearly investment costs of the grid reinforcement alternative, which is based on a life expectancy of 30 years, it is assumed that the required 22 BES units have a life expectancy of 15 years after which they need to be replaced by a new set of 22 BES units for subsequent 15 years. A study by the International Renewable Energy Agency (IRENA) is consulted to estimate the future costs of BES units, which are found to be 58% less in 2030 compared with today's costs of lithium ion battery technologies (Kairies, 2017). The NPV method is used to calculate the yearly costs of investment for BES units based on a 5% discount rate (see Appendix D).

Alternatives / Cash flows [€/year]	Grid Reinforcement	20% BES penetration	Comment
Investment Distribution Assets	-7049	0	NPV, see section 7.1.2
Investment BES units	0	-15250	NPV, with 2nd investment after 15 years
PCR Market	0	11440	Based on 520 [€/BES] Average PCR remuneration
Power Extracted	-10766	-9806	Based on 0,03 [€/kWh] Wholesale price
Power Fed in	5382	4178	Based on 0,03 [€/kWh] Wholesale price
Energy Tax	-35885	-32686	Based on 0,10 [€/kWh], Energy Tax 2018
+			
Total	-48318	-42124	

Table 14: Total System Costs per Alternative for Congestion Management (Belastingdienst, 2018)

The results show that utilizing the Aggregator for congestion management, rather than traditional grid reinforcements, could reduce the total system costs with 6200 from 48.300 to 42.100 [€/year], corresponding to -12,8%. This is primarily caused by the additional income via the PCR market, the reduced power extracted from the grid, and the correspondingly reduced energy taxes. The next section elaborates on the income transfers between the actors in the system in order to assess if this value is captured and by whom.

8.1.2 Actor perspectives

A potential reduction of total costs in the system can be distributed in many different ways, mainly dependent on market dynamics such as wholesale price developments, pricing rules, competition between Aggregators, and contract negotiations. The following two tables, table 15 and table 16, therefore show the cash flows that materialize within the system (i.e. the orange arrows in figure 49) for each congestion management alternative, to provide an example under the various assumptions provided in the comment column.

Economic Welfare Indicators - Grid Reinforcement Alternative with 80% PV and 0% BES penetration

Cash Flows	End-Users (EU)	Aggregator (A)	The DSO	Comment
Power Traded on Wholesale Market [€/year]	-66388	71770	0	A sells at retail price 0,20 [€/kWh] to EU, and EU sells to surplus to market at wholesale price
Investment Costs BES Units [€/year]	0	0	0	
PCR Market [€/year]	0	0	0	
Flex Premium [€/year]	0	0	0	
Congestion Management [€/year]	0	0	-7049	Paid by DSO to A
Energy Taxes [€/year]	0	-35885		Paid by EU through the retail price to A, who must cede it to the authorities at 0,10 [€/kWh]
Additional Network Tariffs [€/year]	-7049	0	7049	Paid by EU to DSO
+				
Total	*-73437*	*35885*	*0*	

Table 15: Example materialization of Economic Welfare Indicators with Grid reinforcements

Economic Welfare Indicators - Aggregator Alternative with 80% PV and 20% BES penetration

Cash Flows	End-Users (EU)	Aggregator (A)	The DSO	Comment
Power Traded on Wholesale Market	-61195	65373	0	A sells at 0,20 ct/kWh to EU, and EU sells to surplus to market at wholesale price
Investment Costs BES Units	-15250	0	0	Costs only for EU
PCR Market [€/year]	0	11440	0	Income for A
Flex Premium	11000	-11000	0	Paid by A to EU
Congestion Management [€/year]	0	7049	-7049	Paid by DSO to A
Energy Taxes		-35885		Paid by EU through the retail price to A, who must cede it to the authorities
Additional Network Tariffs [€/year]	-7049	0	7049	Paid by EU to DSO
Total	*-72494*	*36977*	*0*	

Table 16: Example materialization of Economic Welfare Indicators with an Aggregator

Under the assumed market conditions, it can be concluded from the tables 15 and 16 that end-users capture the additional value as discussed in section 8.1.1, through a cost reduction of -1,3% from 73500 to 72500 [€/year]. The Aggregator on the other hand is able to realize an additional 3% of profits from 35900 to 37000 [€/year].

8.1.2.1 Do ordinary households fall behind?

One important aspect to discuss is the possibly unfair distribution of costs reduction between the individual end-users themselves. So far, the welfare indicator for end-users is calculated by using aggregated inputs produced by the Linny-R model simulations. It implies that the welfare indicators for individual end-users could differ to the disadvantage of ordinary households without a BES unit, since they also have to pay for the costs of congestion management. The following two solutions are suggested to avoid this.

First, the identified costs of congestion management of 7049 [€/year], paid by the DSO to the Aggregator, could be reduced. Each euro that is subtracted from this value is a direct benefit for end-users that do not own a BES unit as compared with the grid reinforcement alternative. However, at what costs the Aggregator can provide congestion management services to the DSO depends, among others, on operational costs and the level of risk coverage. The outcome is therefore primarily determined by the negotiation process between the DSO and the Aggregator.

The second solution is found in implementing a different network tariff structure that charges end-users with PV-systems and/or BES units more than ordinary end-users, e.g. a demand-based time-of-use charge (Bartusch, Wallin, Odlare, Vassileva, & Wester, 2011). The difficulty of implementing this option for one specific grid is acknowledged because DSOs usually have the same tariff structure for all LV distribution grids that they are responsible for. For further reading on this topic, consult the research of Abdelmotteleb, Gómez, Chaves Ávila, & Reneses (2017) who studied the design of efficient distribution network charges in the context of active customers.

8.2 Discussion

The assessment of total system costs in the previous section shows the possibility to create additional value to the system by means of the Aggregator for congestion management. The case study of Eneco CrowdNett in Kijkduin represents a common LV distribution grid in The Netherlands, therewith allowing applicability of the results on other grids. Yet, many assumptions have been made to reduce system complexity or due to lack of information. This section therefore reflects on the used methods, model assumptions, parameter values, and any other factors such as future trends to generalize the results where possible and therewith contribute to the formulation of a thoughtful answer on the main research question in the next chapter.

LP Methodology

First and foremost, consider the methodology. The results in this study are mainly generated by means of optimization. As such, the outcomes show an ideal situation considering the selected data inputs and parameter settings. Uncertainties for both the electricity generated by DERs and the electricity demanded from households are neglected, although this does not make the results useless. The uncertainties on the demand side are to some extent offset by the decision to aggregate all demands into one parameter. However, this applies to a much lesser extent to the uncertainties on the PV production side, as they are considered the cause of the congestions in this study.

It should therefore be kept in mind that different PV profiles lead to different results regarding the number of expected congestions in the system. Nonetheless, the methodology allows to adjust the model according to the specific conditions of any LV distribution grid in terms of substation capacity and production/demand profiles.

Focus on LV substation congestions

That being said, this study focused on the potential congestions at the LV substation and neglected any possible congestions occurring at the underground conductors. All scenario simulations that included a certain amount of PV penetration assumed a geographically equal distribution of PV-systems, whereas in reality those could be located very concentrated potentially causing local congestions. It is attempted to maximally deal with this by including the investment and maintenance costs of underground conductors in the grid reinforcement calculations. The costs of grid reinforcements may therefore be lower if it is found that only the LV substation is the only problem. Similarly, the costs could be higher due to the local characteristics of a certain LV distribution grid, such as a complex network structure or difficult digging environments.

Another important factor possibly affecting the results under different assumptions is the expected PCR power activation. A fixed amount of PCR power is added to the load in each PTU based on historical frequency deviation data. Although the estimation is rather cautious, actual values could be more extreme and become risky especially when the amount of BES unit penetration increases.

Market developments

An important implication from a market development perspective is that it is fundamentally difficult to assess the value of residential BES units for one actor in the supply chain exclusively by means of optimization. Rather, they reveal the theoretical maximum values that could be captured by each actor. Whether and how much value is actually captured by end-users and the Aggregator depends on market dynamics such as wholesale price developments, pricing rules, competition between Aggregators, and contract negotiations.

Starting with price developments from the Aggregator's perspective, the assumed prices for extracting power from and feeding power into the grid are fixed, meaning the results are to some extent sensitive to price changes. However, the prices on the PCR market could have a significant impact. Less remuneration for offering PCR capacity could jeopardize the business case for the Aggregator quite rapidly since her costs (i.e. flex premium) are fixed by contracts with end-users for the long-term. Generating additional income streams once the installed base of CrowdNett participants increases is therefore considered an important development, for example through the SCR market.

Moreover, the zero-sum game characteristic of the system ensures that changing wholesale electricity prices will not strongly influence whether value is created from a system perspective.

Policy developments and Pricing rules

One of the most important characterizations of this study is the removal of the current net-metering support scheme, and consequently allowing end-users to sell their surplus electricity to the grid against the average wholesale price. The resulting price difference between extracting and feeding power from and into the grid creates a maximum incentive for local storage. It is however expected that the support scheme for PV-systems will not be completely removed in the short term, but rather transition via a different support scheme over the long term. It should therefore be kept in mind that the results of this study provide a worst-case scenario in terms financial support schemes.

Besides, the model simulations performed and analyzed in this study are exclusively based on fixed retail prices as a pricing rule. Future power systems may include time-of-use or similar pricing rules, creating a different dynamic between end-users and Aggregators on the market. End-users may in particular show different charging/discharging behavior due to the possibility to charge when the prices are low and discharge when the prices are high, therewith changing the results of this study significantly. Nonetheless, the model allows to include variable prices based on historical time series, implying that the impact of such a pricing rule could be studied via the same methodology as long as accurate and representative data is available.

Competition between Aggregators

Another key assumption is found in CrowdNett being both the Aggregator and the BRP for all the households located in the selected case study. It implies that the Aggregator is sufficiently able to forecast the expected loads in the grid, in particular the demand profiles and with less accuracy the PV production profiles. The avoidance of congestions by charging and discharging the BES units can therefore be optimized as long as the Aggregator has sufficient information about the grid configuration. In reality, this might not be the case due to competition of other Aggregators and therefore has to be carefully considered by the DSO when selecting for the Aggregator's alternative for congestion management.

Future trends

Lastly, all congestions are assumed to arise from feeding surplus PV power into the grid, while congestions originating from peaks in demand are considered out of scope. Developments such as electrification may therefore strongly affect the results of this study, for example due to the deployment of electric heat pumps (HPs) replacing the demand for natural gas, or the increased adoption of electric vehicles (EVs). Both developments are characterized by load profiles that typically are not synchronous with the studied PV-systems that generated power during the day, since HPs and EVs typically require power in during the night. One could argue that SCO via residential BES units then becomes even more lucrative, due to its load shifting capabilities from an end-user perspective. However, the additional demands from HPs and EVs would require more power/energy capacity from BES units, leaving little room for Aggregators to utilize the same BES units for congestion management services.

Although these dynamics are not studied, the Linny-R tool allows to include and analyze them fairly easily, as long as the demand profiles of HPs and EVs are sufficiently available. The total system costs can be studied by using the same methodology, while only changing the parameter settings corresponding with the desired scenario.

8.3 Conclusions on market interactions

Chapter 8 discussed the value of residential BES units from a system perspective by analyzing the total costs of the system and the distribution of cash flows within the system for each congestion management alternative. Based on the gained insights, this section aims to formulate an answer to the following sub-question:

To what extent can the Aggregator reduce the total system costs by offering electric flexibility services to the DSO for congestion management?

Section 8.1 showed that utilizing the Aggregator for congestion management, rather than traditional grid reinforcements could reduce the total system costs with 6200 to 42100 [€/year], corresponding to -12,8%. This is primarily caused by the additional income via the PCR market, the reduced power extracted from the grid, and the corresponding reduced energy taxes. End-users capture this value through a total cost reduction of -1,3%, whereas the Aggregator is able to realize an additional 3% of profits under the assumed market conditions in the case study.

The results of this study have been scrutinized in section 8.2. Especially the PV production profiles are considered an uncertain factor that affects the outcomes of the Linny-R model simulations, since those are the sources of congestion problems. Moreover, the study focusses on the potential congestions at the LV substation and neglects any possible congestions occurring at the underground conductors.

Regarding the identified values for each actor, it is fundamentally difficult to assess the value of residential BES units for one actor in the supply chain exclusively by means of optimization. Rather they reveal the theoretical maximum values that could be captured by each actor. Whether and how much value is actually captured by end-users and the Aggregator depends on market dynamics such as wholesale price developments, pricing rules, competition between Aggregators, and contract negotiations.

Nonetheless, the model allows to include variable prices based on historical time series, implying that the impact of such a pricing rule could be studied via the same methodology as long as accurate and representative data is available. Similarly, the Linny-R tool allows to include and analyze the impact of different assets such as HPs and EVs fairly easily, as long as the corresponding demand profiles are sufficiently available.

Based on these insights, it can be concluded that the Aggregator is able to reduce the total system costs with up to -12,8%, by means of offering flexibility services to the DSO for congestion management, therewith formulating an answer to the final sub-question. Market dynamics determine which actors capture this value and to what extent. Moreover, the applicability of these specific results on other Aggregators and/or LV distribution grids is limited. The Linny-R tool is however able to simulate the behavior of BES units in various PV penetration scenarios, even with the possibility to include HPs and EVs. Yet, the costs of congestion management strongly depend on the local conditions of each grid, making it difficult to generalize the results.

9 Conclusions

The increased penetration of vRES in The Netherlands requires more flexibility to avoid congestions in the LV distribution grids. Aggregators could act as intermediary entities to exploit the flexibility potential of small end-users and create value for DSOs by delivering services that support congestion management. Mechanisms that ensure efficient congestion management will likely be needed, but are currently absent in the Dutch power system, since the value of an Aggregator's electric flexibility services is poorly understood. This report therefore presented the results of a study on the potential value that could be created for DSOs using the Eneco CrowdNett project as a case study. The study is conducted by sequentially analyzing the relevant system components and market mechanisms, assessing the business cases for all involved actors in various scenarios by means of optimization, and synthesizing the results by comparing the two leading alternatives for congestion management with each other from a system perspective. Based on these insights, it is now possible to draw the overall conclusions by formulating an answer to the main research question in section 9.1, followed by the contributions and future research suggestions in section 9.2.

9.1 Main Research question

This research aims to provide a comprehensive understanding of how the value of an Aggregator's electric flexibility services can be determined for DSOs, without jeopardizing the business case for the Aggregator and the CrowdNett participants themselves. The main research question is therefore formulated as follows:

How can the value of Eneco CrowdNett's electric flexibility services, provided by BES units connected to the LV distribution grid, be determined for DSOs?

Chapter 5 discussed the end-user's perspective by analyzing the output indicators self-sufficiency, self-consumption and yearly costs of electricity in a scenario with and without a residential BES unit, by means of the developed Linny-R tool. It showed that a single BES unit could offer 3 up to 4 [kW] of power capacity, and similarly 3,5 to 7,5 [kWh] of energy capacity to the Aggregator, while still ensuring the economic viability of the investment.

The Aggregator's perspective was studied in chapter 6 by analyzing the expected congestions that would occur due to the increase of PV-systems and residential BES units, without considering the network constraints of Kijkduin yet. The BES units, limited by the Aggregator in terms of power/energy capacity, were unable to reduce the frequency of congestions. Still, the study showed the possibility to support the DSO, since the number of so-called congestions weeks remained roughly the same, allowing the Aggregator to withdraw from PCR in those weeks. Moreover, the threshold value of 60% PV penetration was identified therewith showing that higher levels of PV penetration levels would jeopardize the business case of the Aggregator in the form of congestions.

The last perspective analyzed in this study was that of the DSO in chapter 7. It compared the costs of the two alternatives for congestion management, namely grid reinforcements and the load shifting services provided by the Aggregator. The former is estimated to range between 5800 and 9000 [€/year] due to asset upgrades, where the latter cost only 255 [€/year] due to curtailment of surplus PV, therewith clearly identifying the most efficient option.

Chapter 8 elaborated on the systems perspective by analyzing the total system costs and the distribution of cash flows within the system for each congestion management alternative. Based on these insights, it is concluded that the Aggregator is able to reduce the total system costs with up to -12,8%, by means of offering flexibility services to the DSO for congestion management. The discussion section treated the market dynamics that determine which actors are able to capture this value in the form of additional profits or cost reductions. Moreover, this chapter establishes that the applicability of these case-specific results to other Aggregators and/or LV distribution grids is limited. Nonetheless, the Linny-R tool is able to simulate the behavior of BES units in various PV penetration scenarios, even with the possibility to include HPs and EVs.

Referring back to the main research question, the value of Eneco CrowdNett's electric flexibility services for DSOs can therefore ***not*** be determined by exclusively using a Unit Commitment Model with a Linear Programming solver to replicate the behavior of residential BES units located at the LV distribution grid.

The model rather provides a tool to generally assess whether an Aggregator is able to reduce congestions in a given LV distribution network without jeopardizing her own business case and that of the end-users owning the BES units. The model should be supplied with input data regarding residential demand profiles, PV production profiles and the power capacity of the LV substation before the model output can be compared with the expected costs of grid reinforcements on a case-by-case basis to determine the value for DSOs.

9.2 Contribution and recommendation for further research

With the insights provided in this report, a contribution is made towards the need for designing of congestion management mechanisms to postpone or even avoid the need for costly network capacity upgrades as highlighted by Verzijlbergh et al. (2014). This is especially relevant because Veldman (2013) highlighted that 87% of all MV/LV substation in the Netherlands are expected to be overloaded by the time of 2040. It did so through progressing the readers understanding on this subject by:

- Developing an easy-to-use optimization model to generally assess whether an Aggregator is able to reduce congestions in a given LV distribution network without jeopardizing her own business case and that of the end-users owning the DERs
- Demonstrating the possibility for owners of residential BES units to share their asset with an Aggregator without compromising their own business case
- Demonstrating the ability of an Aggregator to reduce the congestions originating from PV-systems through load shifting services, as long as sufficient information about the LV distribution grid is available
- Assessing a particular case study of Eneco CrowdNett and LV distribution grid Kijkduin and showing that the total system costs can be reduced by an Aggregator

In addition to that, the following recommendations are identified for Aggregators, DSOs and scholars to continue the development of the concepts, problems and promising solutions studied in this research. First, Aggregators should continue to find new income streams via other markets (e.g. reactive power and voltage control) in order to really secure the business case for both herself as for the end-users. The DSO is the designated party to cooperate with due to the distributed nature of residential BES units.

Therefore, as a second recommendation, it is advised for DSOs to systematically assess which grids under their responsibility in particular qualify for alternative methods for congestions management and which do not. When a sufficient number of grids qualify, additional study towards the institutional design of congestion management through Aggregators is considered critical to ensure implementation. Moreover, studying a support scheme offered by the DSO is advised to incentivize BES unit deployment from a bottom-up perspective.

Lastly, a valuable addition to this study would be to incorporate the trend of electrification. Especially the inclusion of electric heat pumps and EVs due to their different load profiles. High penetration rates are expected to change the loads in the LV distribution grid significantly, and therewith also the behavior of residential BES units. Whether that is in favor of reducing or increasing congestions, is however still unclear.

Bibliography

Abdelmotteleb, I., Gómez, T., Chaves Ávila, J. P., & Reneses, J. (2017). Designing efficient distribution network charges in the context of active customers. *Applied Energy*, (May), 1–12. https://doi.org/10.1016/j.apenergy.2017.08.103

APX Group. (2017). Day-Ahead Auction. Retrieved August 28, 2017, from https://www.apxgroup.com/trading-clearing/day-ahead-auction/

Bartusch, C., Wallin, F., Odlare, M., Vassileva, I., & Wester, L. (2011). Introducing a demand-based electricity distribution tariff in the residential sector: Demand Response and customer perception. *Energy Policy*, *39*(9), 5008–5025.

Belastingdienst. (2018). Tabellen tarieven milieubelasting. Retrieved January 23, 2018, from https://www.belastingdienst.nl/wps/wcm/connect/bldcontentnl/belastingdienst/zakelijk/overige_belastingen/belastingen_op_milieugrondslag/tarieven_milieubelastingen/tabellen_tarieven_milieubelastingen?projectid=6750bae7-383b-4c97-bc7a-802790bd1110

Burger, S., Chaves-Ávila, J. P., Batlle, C., & Pérez-Arriaga, I. J. (2017). A review of the value of aggregators in electricity systems. *Renewable and Sustainable Energy Reviews*, *77*(April), 395–405. https://doi.org/10.1016/j.rser.2017.04.014

Carreiro, A. M., Jorge, H. M., & Antunes, C. H. (2017). Energy management systems aggregators: A literature survey. *Renewable and Sustainable Energy Reviews*, *73*(December 2016), 1160–1172. https://doi.org/10.1016/j.rser.2017.01.179

ConsuWijzer ACM. (n.d.). No Title. Retrieved August 30, 2017, from https://www.consuwijzer.nl/energie/duurzame-energie/teruglevering/teruglevering-van-elektriciteit

de Vries, L. J., Correljé, A. F., & Knops, H. P. A. (2016). Electricity: Market design and policy choices.

Ecorys. (2014). The role of DSOs in a Smart Grid environment, (April), 145.

Eid, C., Codani, P., Chen, Y., Perez, Y., & Hakvoort, R. (2015). Aggregation of demand side flexibility in a smart grid: A review for European market design. *International Conference on the European Energy Market, EEM*, *2015–Augus*(May), 1–5. https://doi.org/10.1109/EEM.2015.7216712

Eid, C., Codani, P., Perez, Y., Reneses, J., & Hakvoort, R. (2016). Managing electric flexibility from Distributed Energy Resources: A review of incentives for market design. *Renewable and Sustainable Energy Reviews*, *64*, 237–247. https://doi.org/10.1016/j.rser.2016.06.008

ENTSO-E. (2009). P1: Load-Frequency Control and Performance. *Continental Europe Operation Handbook*, (Cc), P1-1-P1-32. Retrieved from https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/Operation_Handbook/Policy_1_final.pdf

Eyer, J. (2009). Electric Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage. *Sandia National Laboratories*, (June).

Frangioni, A., Lacalandra, F., & van Ackooij, W. (2015). Large-scale Unit Commitment under uncertainty : a literature survey Technical Report : TR-14-01 Large-scale Unit Commitment under uncertainty : a literature survey, (January).

Fulchiron, D. (2011). Protection of MV/LV substation transformers. *Gui*, *19*(83), 1–13.

Gaslicht.com. (n.d.). Alles over aansluitingen voor gas en stroom. Retrieved December 5, 2017, from https://www.gaslicht.com/energie-informatie/aansluiting-stroom-gas

Gonzalez-Sotres, L., Mateo Domingo, C., Sanchez-Miralles, A., & Alvar Miro, M. (2013). Large-scale mv/lv transformer substation planning considering network costs and flexible area decomposition. *IEEE Transactions on Power Delivery*, *28*(4), 2245–2253. https://doi.org/10.1109/TPWRD.2013.2258944

Haque, A. N. M. M., Nguyen, P. H., Vo, T. H., & Bliek, F. W. (2017). Agent-based unified approach for thermal and voltage constraint management in LV distribution network. *Electric Power Systems Research*, *143*, 462–473. https://doi.org/10.1016/j.epsr.2016.11.007

Holttinen, H., Tuohy, A., Milligan, M., Silva, V., Müller, S., & Soder, L. (2013). The Flexibility Workout. *IEEE Power and Energy Magazine*, *11*(6), 53–62. https://doi.org/10.1109/MPE.2013.2278000

Hylkema, B. J. (2017). Determinants of profitability in the Dutch positive balancing power market; A case study at AkzoNobel, 72.

Ikäheimo, J., Evens, C., & Kärkkäinen, S. (2010). DER Aggregator Business: the Finnish Case, 38.

Jokić, A. (2007). *Price-based Optimal Control of Electrical Power Systems*. https://doi.org/10.6100/IR629297

Kairies, K.-P. (2017). Battery storage technology improvements and cost reductions to 2030: A Deep Dive. *International Renewable Energy Agency Workshop*. Retrieved from https://costing.irena.org/media/11341/2017_Kairies_Battery_Cost_and_Performance_01.pdf

Kakorin, A., Laurisch, L., & Papaefthymiou, G. (2015). FLOW Dynamic Power Management _ WP2 . 2 : Market Interaction. Retrieved from http://www.ecofys.com/files/files/ecofys-2015-flow-dynamic-grid-wp2-2-market-interaction.pdf

Klein Entink, M. E. (2017). Benefits of local electrical energy storage for a distribution system operator, 146.

Kristov, L., & Martini, P. De. (2014). 21 st Century Electric Distribution System Operations, (May), 1–11.

Lumig, M. van, & Locht, M. (2009). Impact DG en “nieuwe belastingen” op het LS-net in bestaande woonwijken, 225. https://doi.org/10.1007/BF00175233

Lumig, M. van, & Uytterhoeven, S. (2009). Literatuurstudie naar meest voorkomende wijken en woningen. Retrieved from www.laborelec.com

Masson, G., Pvps, I. E. A., Briano, J. I., Jesus, M., & Creara, B. (2016). a Methodology for the Analysis of Pv Self-Consumption Policies, 1–16.

Moreno, R., Moreira, R., & Strbac, G. (2015). A MILP model for optimising multi-service portfolios of distributed energy storage. *Applied Energy*, *137*, 554–566. https://doi.org/10.1016/j.apenergy.2014.08.080

Nguyen, P. H. (2010). *Multi-Agent System based Active Distribution Networks*. *PhD Dissertation*. https://doi.org/10.6100/IR693215

Nordhaus, W. D., & Samuelson, P. A. (2004). *Economics*. *Economics* (19th ed.).

Rijkswaterstaat. (2015). Open Data. Retrieved December 8, 2017, from https://www.rijkswaterstaat.nl/zakelijk/open-data

SJG Dijkstra and AJ van der Welle. (2012). Optimale interactie tussen marktpartijen en netbeheerders in de transitie naar smart grids, 1–8.

Spiliotis, K., Ramos Gutierrez, A. I., & Belmans, R. (2016). Demand flexibility versus physical network expansions in distribution grids. *Applied Energy*, *182*, 613–624. https://doi.org/10.1016/j.apenergy.2016.08.145

Stedin. (2014). Jaarverslag 2013, 186. Retrieved from http://www.elia.be/~/media/files/Elia/publications-2/annual-report/Jaarverslag_2013.pdf

TenneT. (2017). Primary Reserve. Retrieved August 29, 2017, from http://www.tennet.org/english/operational_management/system_data_preparation/primary_reserve.aspx

USEF Foundation. (2015). *USEF: The Framework Explained*. Retrieved from http://www.usef.info/Framework/Download-the-Framework.aspx

Vegte, H. van der, Melzen, M. van, & Spek, H. van der. (2016). Nationaal Actieplan Energieopslag, 18–23.

Veldman, E. (2013). *Power Play Impacts of flexibility in future residential electricity demand on distribution network utilisation*. https://doi.org/10.6100/IR761384

Verzijlbergh, R. A., Vries, L. J. De, & Lukszo, Z. (2014). Renewable Energy Sources and Responsive Demand . Do We Need Congestion Management in the Distribution Grid ?, *29*(5), 2119–2128.

VVD, CDA, D66, & ChristenUnie. (2017). Vertrouwen in de toekomst - Regeerakkoord 2017 – 2021.

Appendix A: Key Figures Grid Reinforcement Costs

TABLE III
CHARACTERISTICS OF THE URBAN 20/0.4-kV TRANSFORMER SUBSTATIONS

Rated Power (kVA)	No-load Losses (kW)	Load Losses (kW)	IC (€)	PMP (€)	CMC (€)
110	0.147	2.647	15,000	1,200	6,800
390	0.588	2.852	18,000	1,200	6,800
810	0.859	4.101	19,000	1,200	6,800
1000	1.000	5.000	20,000	1,200	6,800
1100	1.300	5.294	21,000	1,200	6,800

TABLE V
CHARACTERISTICS OF THE UNDERGROUND CONDUCTORS

Rated Current (A)	Rated Voltage (kV)	R (Ω/km)	X (Ω/km)	IC (€/km)	PMP (€/km)	CMC (€)
98	0.4	0.707	0.058	9,000	5.4	610
310	0.4	0.393	0.060	11,000	5.4	610
370	0.4	0.207	0.065	12,000	5.4	610
460	0.4	0.112	0.072	15,000	5.4	610
640	20	0.086	0.055	41,000	630	6,100

TABLE IV
CHARACTERISTICS OF THE RURAL 20/0.4-kV TRANSFORMER SUBSTATIONS

Rated Power (kVA)	No-load Losses (kW)	Load Losses (kW)	IC (€)	PMP (€)	CMC (€)
30	0.170	1.429	7,800	460	3,000
110	0.327	2.647	8,400	460	3,000
290	0.476	3.154	9,400	460	3,000
380	0.722	2.708	10,000	460	3,000
810	1.000	4.101	13,000	460	3,000

TABLE VI
CHARACTERISTICS OF THE OVERHEAD CONDUCTORS

Rated Current (A)	Rated Voltage (kV)	R (Ω/km)	X (Ω/km)	IC (€/km)	PMP (€/km)	CMC (€)
86	0.4	1.600	0.100	11,000	5.4	610
160	0.4	0.482	0.098	15,000	5.4	610
240	0.4	0.209	0.093	18,000	5.4	610
330	0.4	0.042	0.088	22,000	5.4	610
530	20	0.113	0.361	52,000	1,300	1,800

Appendix B: Characterization Living Environments in The Netherlands

Kenmerken van de 13 woonmilieutypen

Kenmerken / Woonmilieutypen	Aantal van het woonmilieu in NL	Vooroorlogse won.	Eengezins won.	Vrijstaande won.	Dichtheid woongebied (per ha)	Dichtheid totaal	Winkels per 1000 huishoudens	Gezinnen
Centrum-stedelijk-plus	34	63,3%	16,7%	1,8%	77,8	59,3	49,2	16,0%
Centrum-stedelijk	37	31,9%	53,2%	4,1%	42	27,2	96,6	18,1%
Stedelijk vooroorlogs	115	65,0%	38,2%	2,1%	65,8	36,6	18,7	25,6%
Stedelijk NO compact	238	17,1%	37,8%	2,1%	46,6	20,4	10,8	29,6%
Stedelijk NO grondgebonden	166	15,7%	76,1%	5,9%	32,7	11,6	9,6	38,8%
Groen-stedelijk	196	16,7%	64,0%	11,1%	23,0	5,5	8,6	34,4%
Centrum-kleinstedelijk	78	20,8%	68,3%	9,7%	28,1	11,1	68,8	28,1%
Kleinstedelijk	202	12,0%	70,9%	6,2%	32,6	8,6	8,4	39,5%
Groen-kleinstedelijk	204	12,3%	80,8%	15,1%	21,1	4,6	8,6	39,7%
Centrum-dorps	358	15,4%	88,3%	18,2%	23,2	2,9	20,6	40,8%
Dorps	488	18,0%	94,6%	34,4%	20,6	1,1	16,3	42,8%
Landelijk bereikbaar	1473	27,1%	91,7%	50,8%	19,9	0,4	9,4	43,8%
Landelijk perifeer	427	33,3%	93,5%	54,4%	19,5	0,3	12,4	42,0%

Appendix C: Output Indicators – Second set of experiments

The following table shows the output indicators for the second set of experiments as identified in section 6.1.2 with the exclusion of PCR power. The difference with the first set of experiments is therefore only found in the restricted power/energy capacity of the BES units. Where the first set allowed the BES units to charge/discharge with 5 [kW] power and 13,5 [kWh] energy capacity, the second set of experiments as shown below only allowed the BES units to charge/discharge with 1 [kW] of power and 11,5 [kWh] of energy capacity.

LinnyR Output Indicators - Unconstrained Grid - BES Unit restricted at 1 kW SCO ***without*** PCR Activation						
Scenario	Installed PV [%]	Installed BES [%]	Max Feed-in [kW]	Grid SC Ratio [%]	Freq. Sub-station Overloads [#]	Freq. Congestion weeks [#]
e2.1	20	0	24	95,9	0	0
e2.2	20	20	3	97,7	0	0
e2.3	40	0	103	76,1	0	0
e2.4	40	20	81	84,4	0	0
e2.5	40	40	60	89,8	0	0
e2.6	60	0	189	60,5	0	0
e2.7	60	20	168	69,3	0	0
e2.8	60	40	146	76,1	0	0
e2.9	60	60	124	81,5	0	0
e2.10	80	0	272	50,6	838	23
e2.11	80	20	251	58,8	475	20
e2.12	80	40	229	65,6	216	15
e2.13	80	60	207	71,4	26	6
e2.14	80	80	233	75,5	13	2
e2.15	100	0	355	43,4	1947	30
e2.16	100	20	334	51,0	1470	28
e2.17	100	40	312	57,5	1106	26
e2.18	100	60	289	62,9	819	23
e2.19	100	80	327	66,4	598	21
e2.20	100	100	345	68,3	527	19

Table 17: Output Indicators per Scenario - Second Set of Experiments (a)

Appendix D: NPV yearly investment costs of BES units

This appendix elaborates on the investment costs as discussed in section 8.1.1. The value of 15250 [€/year] was found to create a positive NPV value after 30 years as shown in the figure below. The kink in the curve is created by an additional investment in 22 new BES units since it is assumed that the first 22 assets have a life expectancy of 15 years. A study by the International Renewable Energy Agency (IRENA) is consulted to estimate the future costs of BES units, which are found to be 58% less in 2030 compared with today's costs of lithium ion battery technologies (Kairies, 2017).