Aggregated Flexibility to support Congestion Management

Robin Brouwer
Complex Systems Engineering & Management, TU Delft
Graduate Student
TU Delft

Co-authors:
Ozge Okur
PhD candidate Engineering Systems and Services, TU Delft
Dr. Pieter Bots
Multi Actor Systems, TU Delft

***Abstract* — Increased variable renewable energy sources requires more flexibility that could be provided by distributed energy sources located at small end-users. Aggregators could act as intermediary entities to exploit the flexibility potential of small end-users and create value for DSOs by offering congestion management services. An optimization model based on Linear Programming is developed and used to compare two alternatives for congestion management for a case-study in The Netherlands. The results show that the Aggregator could reduce the total system costs with -12,8% as compared with traditional grid reinforcements. 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.**

***Index Terms*--: Congestion Management, Aggregator, BES, Flexibility, Distribution Grid**

NOMENCLATURE

Parameters	
η^B	Charging/discharging efficiency of BES unit
η^{PV}	Efficiency of PV system
λ_t^{Feed}	Feed-in electricity price for selling electricity [€/kWh]
λ^{Off}	Retail electricity price for buying electricity [€/kWh]
E_{max}^B	Maximum energy capacity of BES unit [kWh]
E_t^{Loss}	Fixed self discharge losses [kWh]
P_{max}^B	Maximum power capacity of BES unit [kWh/PTU]
$P_{max}^{Connection}$	Maximum power capacity of LV substation [kWh/PTU]
P_t^{Dem}	Total energy consumption by loads at time $t \in \{1, 2, ..., T\}$ [kW]
P_t^{PV}	Solar generation at time $t \in \{1, 2, ..., T\}$ [kWh]
T	Total number of hours
Variables	
E_t^B	State of BES unit at time $t \in \{1, 2, ..., T\}$ [kWh]
P_t^{Cur}	Power curtailed from PV system at time $t \in \{1, 2, ..., T\}$ [kWh]
P_t^C	Power charged into BES unit originating from the PV system at time $t \in \{1, 2, ..., T\}$ [kWh]
P_t^D	Power discharged from BES unit to supply local demand at time $t \in \{1, 2, ..., T\}$ [kWh]
P_t^{Feed}	Electricity feed-in to the grid at time $t \in \{1, 2, ..., T\}$ [kWh]
P_t^{Off}	Electricity off-take from the grid at time $t \in \{1, 2, ..., T\}$ [kWh]

I. INTRODUCTION

Variable Renewable Energy Sources (vRES) are increasingly penetrating the power system causing more intermittency due to weather dependent production patterns. In order to cope with the additional uncertainty, more flexibility is needed in the power system. 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, De Vries, & Lukszo et al., 2014) and reinforcements of the network requires 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.

DERs are characterized by their small capacities, and their connection to low and medium voltage electricity distribution grids (Burger, Chaves-Ávila, Battle, & 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). Aggregators can therefore 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).

An aggregator is able to gather flexibility from DERs and therewith provide flexibility services to various market parties such as suppliers, Transmission system operators (TSOs) and Distribution system operators (DSOs). This paper focusses particularly on congestion management services for DSOs since it is expected that 87% of all Medium-Voltage (MV)/Low-Voltage (LV) transformers in the Netherlands will be overloaded by the time of 2040 (Veldman, 2013). 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 Primary Control Reserve (PCR) and Secondary Control Reserve (PCR) 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. 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, Ramon 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.

This paper aims to contribute to the design of such mechanisms and therewith potentially reduce the costs of congestion management by:

- Exploring the Aggregator's flexibility services for congestion management purposes
- Developing an easy-to-use optimization tool to assess whether an aggregator is able to reduce congestions in a given LV distribution network.
- Comparing the cost of traditional grid reinforcements with the cost of congestion management through the Aggregator's flexibility services.

The paper is therefore structured as follows. Section II describes the system. Section III elaborates on the problem formulation in terms of optimization equations, decision variables, datasets, parameter settings, and output indicators. Subsequently, the results as well as a discussion are provided in Section IV, followed by the conclusions in Section V.

II . Model description

A. System analysis

In this paper, the end-users own a combined system of solar photovoltaics (PVs) and residential Battery Energy Storage (BES) units.

A PV-BES system is beneficial for the end-users since it enables them to increase their local PV consumption and to be more self-sufficient. On the other hand, when some of these BES unit capacities are shared with an aggregator, they can be operated to provide other flexibility services such as PCR services for TSOs and congestion management for DSOs. This creates. This sharing mechanism which creates a viable business case for both the end-users and the Aggregator is illustrated in Figure 1.

Furthermore, the scope of congestion management in this

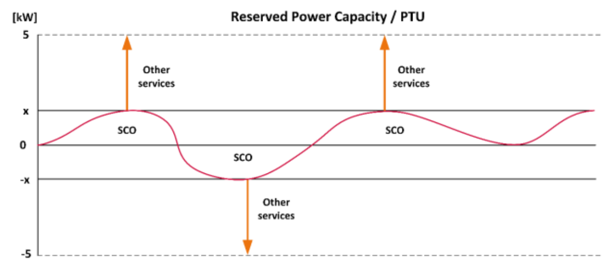

Fig. 1: Example Power Output BES unit

paper is the line flow in the LV substation as highlighted with a green dot in Fig. 2. The black lines represent the assets under the responsibility of the TSO, where the yellow lines represent those of the DSO. The sub-system circled in red represents the system selected for this paper.

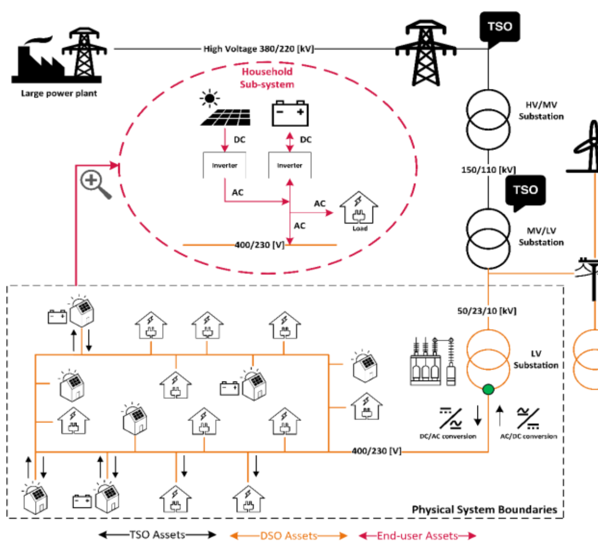

Fig. 2: System Overview

The power and energy capacity of the system is 5 [kW] and 13,5 [kWh] respectively. Fig. 1 provides an example of the power output of the BES unit in [kW/PTU] where the values for x and –x are contractually recorded between the aggregator and the end-user. In other words, these values represent the reserved upward and downward power capacity of the BES unit for the purpose of SCO. Moreover, in this system, the BES unit can only be charged via the PV-system.

B. *Assumptions*

The results presented in this paper are based on the following assumptions:

- Uncertainties for both the electricity generated by DERs and the electricity demanded from households are neglected.
- All congestions analyzed are assumed to arise from feeding surplus PV power into the grid, while congestions originating from peaks in demand are considered out of scope.
- The Aggregator is also the responsible Balance Responsible Party for all the households in the system. It implies that the aggregator is able to forecast the expected loads in the grid, in particular the demand profiles and the PV production profiles. Therefore, the avoidance of congestions by charging and discharging the BES units can be optimized as long as the Aggregator has sufficient information about the grid configuration.
- ICT requirements to exchange data are available for the Aggregator.
- The cost of battery degradation is not considered.
- Net-metering policy is assumed to be absent in the system.

III. Problem formulation

The system active on the LV distribution grid of Kijkduin can be framed as a Unit Commitment Problem (UCP) in which the generation units are represented by the residential BES units. They primarily deliver the SCO and PCR services, but can also deliver load shifting services for the purpose of congestion management.

The PCR service is excluded from the optimization model due to its second-to-second activation via an automated control mechanism that would unnecessarily complicate the model without gaining new relevant insights. Therefore, it is decided to calculate the PCR service activation ex-post based on grid frequency deviation data.

In this paper, the generation units of the UCP are represented by Eneco CrowdNett's residential BES units that either charge or discharge based on the local conditions of the end-user. Similarly, load shifting services ensure that BES units charge or discharge extra power according to the congestions in the distribution grid. By doing so, the system aims to minimize the total costs according to the prices assigned to the following processes. The amount of power extracted from and fed into the grid, the charging and discharging behavior of the BES unit, and a possibility to curtail PV power together form the degrees of freedom that eventually determine the total costs of the system.

A. *Mathematical Formulation*

This UCP with PV and BES units can be formulated as a Linear Programming problem in which the electricity cost of end-users is minimized. The symbols used here are given in the nomenclature section. The objective function in Equation (1) aims to minimize the total costs of electricity of end-users which consists of the expense of buying electricity, and the revenue gained by selling surplus PV production. Note that the power offtake and power feed-in represent the first two decision variables.

$$\text{Minimise} \quad \sum_{t=1}^{T} \lambda_t^{Off} P_t^{Off} - \lambda_t^{Feed} P_t^{Feed} \tag{1}$$

subject to

$$P_t^{Off} + P_t^{PV}\eta^{PV} - P_t^{Feed} - P_t^{C}\eta^{B}\eta^{PV} + P_t^{D}\eta^{B} = P_t^{Dem} + P_t^{Cur} \quad \forall t \tag{2}$$

$$E_t^B = E_{t-1}^B + P_t^C\eta^B\eta^{PV} - P_t^D\eta^B - P_t^{Loss} \quad \forall t \tag{3}$$

$$0 \le E_t^B \le E_{max}^B \quad \forall t \tag{4}$$

$$P_t^C \le P_{max}^B \quad \forall t \tag{5}$$

$$P_t^D \le P_{max}^B \quad \forall t \tag{6}$$

$$P_t^{Feed} + P_t^{Off} \le P_{max}^{Connection} \quad \forall t \tag{7}$$

Satisfying local power demand is ensured using Equation (2), which describes 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. However, the system would 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 limited in Equation (7).

The state of the BES unit E_t^B and its charging and discharging behavior are given by Equation (3-6). They describe the in- and outflow of electricity according to the maximum power capacity of the BES unit.

Note that the variables P_t^C and P_t^D represent the final two decision variables. Finally, the maximum capacity of the LV substation is given by (7). All equations are implemented in the software tool Linny-R solved with a LP solver.

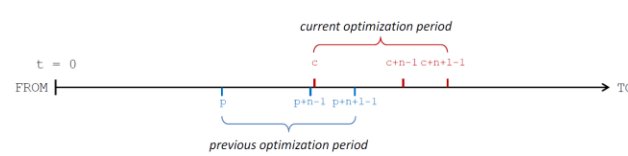

Fig. 3: Optimization periods in Linny-R (Bots, cited in Hylkema 2017)

Merely minimizing the costs of the system over time would provide the static behavior of the BES units given the time horizon established by the input data, and based on perfect knowledge regarding the entire dataset. Therefore, a rolling time horizon is used to provide the BES units with perfect knowledge for a limited period of time representing a more realistic system (see Fig. 3).

It shows that the current period *c* is optimized based on the information of that entire period plus information of an additionally defined look-ahead period *l*.

B. Ex-post PCR Activation

The activation of PCR, added ex-post to the optimization model, is estimated based on historical frequency deviation data obtained from Regelleistung, the cooperation partner for PCR tenders of TSO TenneT, with a resolution of one second. Basic statistical analysis has shown that the requested PCR power capacity is very likely, based on μ +/- 3σ, to be below 25 [kW] in the selected case study, assumed that the data is normally distributed. The value of 25 [kW] is subtracted from the parameter 'Max Substation Capacity' to compensate for the expected PCR power request.

C. Input data and parameter settings

The two most important datasets implemented in the Linny-R software are the residential demand and PV production profiles. Residential demand profiles are retrieved from The Dutch Energy Data Exchange Association (NEDU, 2017). It should be noted that the data consists of the average values for the electricity consumption in a particular Power Time Unit (PTU), implying that the power through the connection point deviates in reality. By aggregating the demand profiles of all connected households into a single parameter, this deviation is assumed to be offset.

The PV profiles are obtained via the forecasting department at Eneco Energy Trade and based on actual weather data collected at the weather station in Rotterdam. Deviations caused by different locations and angles with respect to the sun are similarly offset by the aggregation of all profiles into a single parameter. Both the demand as the PV production profiles are taken from 2016.

In order to select a LV distribution grid for the case-study, the HERMES DG 3 project is consulted. The project identified the most representative LV distribution grids used in residential areas in The Netherlands (Lumig, & Locht, M., 2009). It has been found that the neighborhood of Kijkduin just outside The Hague is very suitable to study, since it allows for increased PV-system penetration in the future. The total number of individual connections in the meshed network structure is 111 and the LV substation's maximum power capacity is 196 [kW].

By gradually increasing the number of PV-systems in the grid, it is found that congestions occur at approximately 70-80% corresponding to a maximum overload of 72 [kW] at the LV substation. Therefore, a scenario with 80% PV penetration and 20% BES penetration is selected to compare the two alternative for congestion management. This number of BES units ensures sufficient power capacity to avoid the expected congestions.

Table I presents the parameter settings for the load shifting optimization, which are based on the selected case-study of Eneco CrowdNett, and the distribution grid in Kijkduin. The system avoids congestion by including a constraint on the maximum substation capacity, while still minimizing the total costs of the system. Important to discuss is that the end-user parameters are aggregated and implemented according to the grid parameters as presented in table I. For example, the parameter 'BES Unit Energy Capacity' is implemented as 111 * 20% * 11,5 = 253 [kWh].

The BES unit power and energy capacity of 1 [kW] and 11,5 [kWh] respectively represent the SCO values for x and –x as identified in figure 1. Moreover, note that the 'Max Substation Capacity' is corrected by 25 [kW] compared with its original capacity of 196 [kW]. This is the result of the expected PCR activation as discussed previously.

General Timeframe: **35136** PTU's in **2016**		
Grid Parameters	**Value**	**Unit**
Number of Households	111	[#]
PV Penetration	80	[%]
BES Unit Penetration	20	[%]
Max Substation Capacity	171	[kW]
End-user Parameters	**Value**	**Unit**
AEC-profile	5015	[kWh/year]
PV-system Capacity	5	[kWp]
PV Inverter efficiency	98	[%]
BES Unit Energy Capacity	11,5	[kWh]
BES Unit Power Capacity	1	[kW]
BES Unit Inverter Efficiency	90	[%]
Initial State-of-Charge	6,75	[kWh]
Self-discharge Rate	2,31E-05	[kWh/PTU]
Max Connection Capacity	30	[kW]
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		

TABLE I: Parameter Settings Load Shifting Optimization

D. Output Indicators

In this study, two congestion management alternatives are compared with each other based on total system costs. The first alternative is traditional grid reinforcements, whereas the second one is load shifting by means of an Aggregator. Regarding the former, the costs of grid reinforcements in the LV distribution grid of Kijkduin is the only factor affecting the total system costs, which are estimated by means of an Net Present Value (NPV) calculation based on doubling the substation capacity with a life time expectancy of 30 years, and reinforcing 4 [km] of underground conductors. The discounted yearly costs of grid reinforcement are found to be 7049 [€/year] using key figures obtained from a study of Gonzalez-Sotres, Mateo Domingo, Sanchez-Miralles, & Alvar Miro (2013).

The other alternative, load shifting by means of an Aggregator, however affects the total system costs in multiple ways. First, the discounted yearly costs of the BES units themselves are found to be 15.250 [€/year] based on 22 BES units which are replaced after 15 years by another 22 BES units due to their life time expectancy. Second, the revenues generated in the PCR market are assumed 11.440 [€/year] based on the average PCR remuneration in 2016 of 2.500 [€/MW/week] apportioned to 22 BES units. The other factors affecting the total system costs are generated as output of the optimization model. Primarily the reduced power offtake from and power feed-in the grid valued at 0,03 [€/kWh] together with the corresponding energy taxes valued at 0,10 [€/kWh].

The total system costs for both congestion management alternatives are therefore defined as the sum of the discounted yearly costs of new assets, the PCR market revenues, the costs for power extracted and the revenues for power fed into the grid both valued at the wholesale electricity price, and the costs of energy taxes.

IV. RESULTS

A. System behavior

Figure 3 shows one summer week of model output in [kWh/PTU] as a result of the optimization defined in table I. The orange surface is plotted as negative values, since that is how the PV production profiles are implemented in the software tool Linny-R. The yellow and purple lines represent the charging and discharging processes respectively. They alternate depending on the available PV power, whereas charging typically occurs during the day, and discharging typically occurs during the night. Note that both those processes are utilized according to their maximum defined power capacities.

The offtake and feed-in processes shown in blue and green respectively are also dependent on the available PV production. Some power is curtailed on four of the seven days showed in black, because the top of the graph represents the maximum substation capacity. Note that the BES charging process is always maximally utilized in those cases of curtailment, therewith showing the system's attempt to avoid congestions in the grid.

Figure 4 shows the same optimization run, yet only the model output required to calculate the output indicators in order to compare the two alternatives for congestion management. It clearly shows the seasonal effect, since the graph contains simulated model output for a full year. The computed offtake and feed-in values are the result of the charge/discharge processes of the aggregated BES units as shown in figure 3. Note that power is only curtailed if the LV substation capacity reaches its maximum, i.e. the top of the graph in figure 4. This also implies that the BES units' maximum power and/or energy capacity is reached.

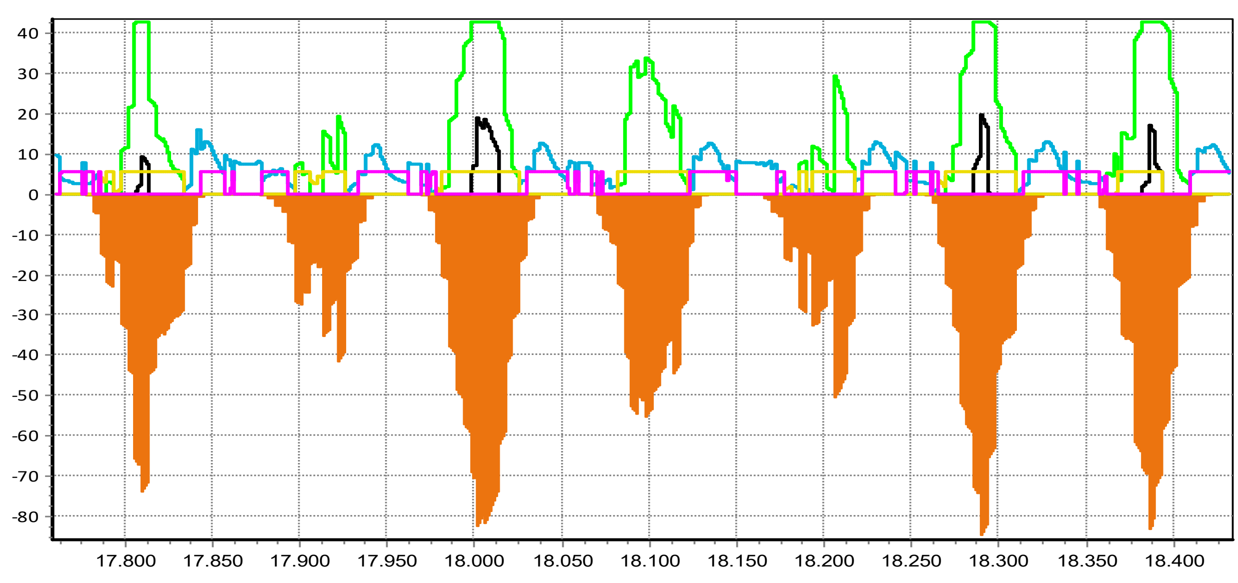

Figure 3: System Behavior - Blue, green, black, orange, yellow, and purple represent Offtake, Feed-in, Curtailment, Solar-PV production, BES Charge, BES Discharge respectively

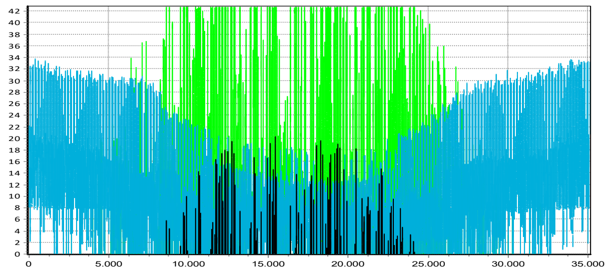

Figure 4: System Behavior – Blue, green, and black represent Offtake, Feed-in, and Curtailment respectively

B. Total System Costs

The model outputs, in particular as shown in figure 4, are used to compare the two congestion management alternatives with each other based on the identified output indicator: total system costs. Figure 5 shows the associated costs and revenues for both alternatives.

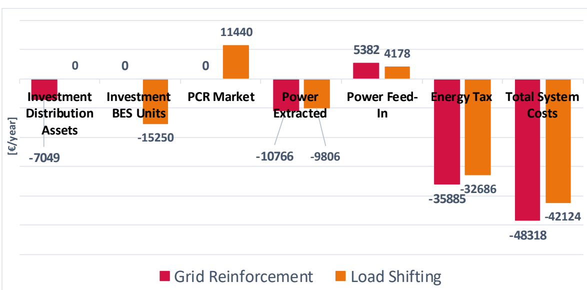

Figure 5: Comparison of Congestion Management Alternatives

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.

V. Conclusions

Aggregators are able to gather flexibility from DERs to provide flexibility services to various market actors such as suppliers, TSOs, and DSOs. This paper particularly focused congestion management services for DSOs by developing an optimization model that explores the possibility for Aggregators to reduce congestions in a given LV distribution network.

The optimization model is used to compare the traditional grid reinforcement with a load shifting alternative through an Aggregator for the purpose of congestion management. A combined system of PV and a BES unit operated by the Aggregator Eneco CrowdNett active on a representative LV distribution grid in The Netherlands is assessed in terms of total system costs as a case-study.

It is found that the Aggregator could reduce the total system costs with 6200 from 48.300 to 42.100 [€/year], corresponding to -12,8% as compared with traditional grid reinforcements. 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.

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, but also uncertainties in residential demand and PV production profiles. Therefore, it is suggested to incorporate these market dynamics and uncertainties for further research in order to better understand the role of Aggregators in future power systems.

References

[1] 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

[2] 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

[3] 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

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

[5] 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

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

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

[8] 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

[9] 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

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

[11] 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.