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Modelling of residential side flexibility for distribution network planning

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Przede wszystkim jednak, dziękuję moim rodzicom, Jackowi i Ewie. Bez was i waszego wsparcia ostatnie dwa lata nie byłyby możliwe. Dziękuję.

Executive summary

With the environmental impacts of the fossil fuel economy being more and more visible it became oblivious that action against further climate change needs to be taken. This led to the energy transition effort undertaken by countries of the European Union with the goal of increased usage of sustainable energy at the cost of non-renewable fuel sources. And on the national level, it led to more regionalized targets.

With this in mind, the Netherlands adopted several goals with a target of reducing dependence on fossil fuels. These ranged from a bigger percentage of renewable energy in energy supply, through electrification of heating, to widespread adoption of electric vehicles. All of these introduce changes to how the energy system is operated. And this is particularly visible for electricity distribution system operators. These new developments could mean that the grid assets that were previously assumed to be functioning for the next decades would be retired earlier than expected. However, progress in areas of flexibility in electrical energy consumption present opportunity for deferred replacement of those otherwise prematurely retired assets.

In this context, the main objective of this thesis was to assess the benefit that activation of electrical energy flexibility in households could bring to the distribution system operator. Between two energy transition scenarios considered and different simulation settings, it was discovered that from 3.3 to 35.4% cumulative investments into grid assets could be deferred in next 8 to 10 years into the future, for considered networks. This corresponds to between 1.1 and 16.7 million € for examined networks, which contained about 5% of assets (transformers, medium and low voltage cables) belonging to the Dutch distribution system operator Enexis. However, in order to arrive at these values, the following steps had to be taken.

Firstly, possible methods used to activate flexibility were researched and compared. These included tariff- and market-based solutions, connection agreements and direct control approach. Based on the review of current literature and pilot projects it was decided that power-based tariffs were the most aligned with the goal of reducing the impact onto the DSO’s grid assets with presented requirements. This decision was taken due to the cost-reflectiveness of network asset usage presented by power-based tariffs. It was further reinforced by the fact the main criterion considered during asset sizing is expected loading since in medium and low voltage networks peak power corresponds to the majority of costs. Beside technical effectiveness, the power-based tariff was found to promise opportunity in other aspects. Those were social acceptance, influenced by customers already being accustomed to the tariff system, the readiness of technology behind this approach and compliance with the legislative framework.

Secondly, based on the outcome of the previous step it was decided to model the impact of the power-based tariff onto the grid assets. In order to analyse the impact of the potential solution onto the real grid assets, the model was incorporated into the Enexis’ Scenariotool - bottom-up scenario analysis tool developed for short to medium-term network planning purposes. This decision posed a strict requirement onto a high computational performance in order to allow examination at network scale within the feasible timescale. The proposed model focused on simulating the possible impact of the power-based tariff on the residential load profiles with a focus on electric vehicle charging and photovoltaic panel generation.

Thirdly, model results were examined from the single household level up to multiple low voltage networks and connecting medium voltage network fragments. Examinations at the network level were run for multiple sets of possible scenarios. Then based on the comparison with the baseline scenario, ones without activation of flexibility, assets for which deferred replacement is possible were identified. These deferral possibilities were later translated into the monetary values of cumulative savings up to a given year of simulation, resulting in the figures presented in the beginning.

In conclusion, this project identified optimal method, from the viewpoint of DSO, for activation of flexibility from the households, presented model that modifies residential loads according to this method and performed an economic evaluation of the tariff’s impact onto the part of DSO’s grid.

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Nomenclature

Here all the abbreviations, variables and parameters along with letters/characters and SI unit are introduced.

Variable/Parameter name	Symbol / Abbreviation / Short name	Units
Balance Responsible Party(-ies)	BRP(s)	-
Battery Electric Vehicle(s)	BEV(s)	-
Constant – an indication that value does not change	const.	-
Demand Side Management	DSM	-
Distribution System Operator(s)	DSO(s)	-
Electric Vehicle(s)	EV(s)	-
Enexis' short to midterm network planning tool / bottom-up energy transition scenario analysis tool	Scenariotool	-
EV charging speed setting	ch	kW
Heat Pump(s)	HP(s)	-
High Voltage	HV	V
Household(s)	HH(s)	-
Low Voltage	LV	V
Medium Voltage	MV	V
Photovoltaic panel(s)	PV(s)	-
Powerband tariff threshold value	lim	kW
Scenario names used in the document	'GG', '50'	-
Season setting for simulation	seas	-
Summer	su	-
Transmission System Operator(s)	TSO(s)	-
Winter	wi	-

Most important variables used for model (Chapters 4.3.2 and 4.3.3)	Symbol	Units
Capacity to charge	CC	kW
Capacity to charge Boolean matrix	CCM	1/0
Cumulative capacity to charge	CCC	kW
Driving efficiency of EV	$\eta_{driving}$	km/kWh
Energy required to charge	E_{charge}	kWh
Length of the car trip	d_{trip}	km
Power consumed by EV charging	P_{EV}	kW
Power consumed by heat loads	P_{HP}	kW
Power consumed by household baseload	P_{HH}	kW
Power produced by PV panels	P_{PV}	kW
Set threshold of the powerband	P_{band}	kW
Total power at the household connection with the grid (possibly without technology optimized for)	P_{sum}	kW

1. Introduction

1.1. Energy transition

With the environmental impacts of the fossil fuel economy being more and more visible it became oblivious that we need to change our behaviour and start taking the boundaries of our planet into account [1]. It introduced the need to shift how we think over multiple aspects of our lives. To put out reliance on fossil fuels we should start with the pre-industrial era.

Before the year 1751, there were almost no emissions – the number of ~3 million metric tons is assumed to be constant for up to 1751 and this amount of emissions is absorbed by natural sinks. The real increase in emitted carbon started with the industrial revolution in the 19th century. From this point onwards the emissions rapidly increased up to almost 10000 million metric tons in the year 2014. The scale of the increase can be clearly seen in Figure 1.1.

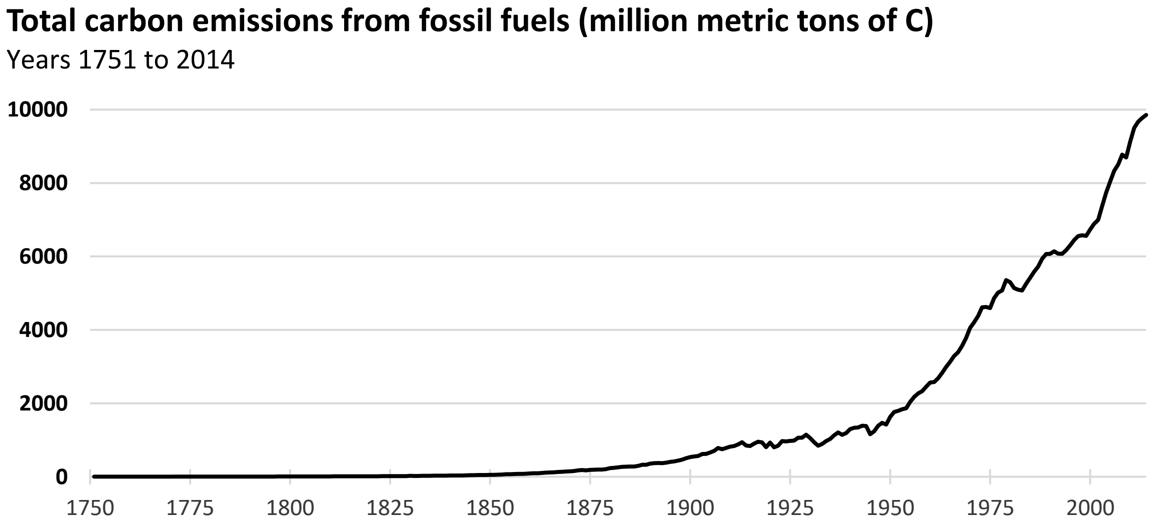

Figure 1.1 Total carbon emissions from fossil fuels [2]

The impact of said CO_2 emissions is already visible – the global temperatures have risen by 1.1°C since pre-industrial levels and the process doesn't seem to be stopping, as presented in Figure 1.2.

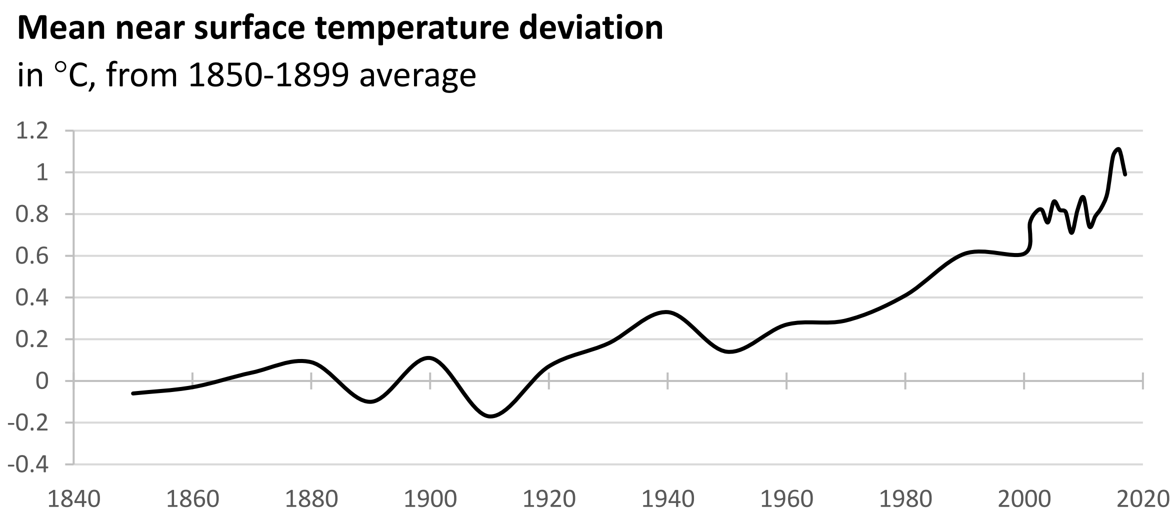

Figure 1.2 Mean near surface temperature deviation [3]

Those changes might provoke a question “Who is responsible for those emissions?”. The fact that their rapid increase coincides with the start of the wide-spread use of fossil fuels indicates that humanity is responsible for those.

To continue on the previous question, we can try to further identify which areas of human activity are most impactful. According to the International Energy Agency (IEA) data in the year 2016, the economic sectors that produced the most emissions were: electricity and heat, transport, industry, buildings, and all other [4]. The majority of the CO_2 introduced into the atmosphere comes from the electricity and heat sectors – they accounted for more than 41% of total emissions. Those numbers are put into perspective in Figure 1.3.

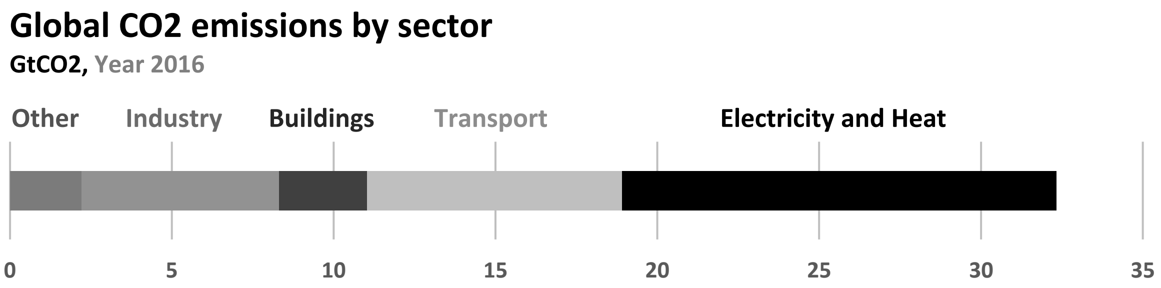

Figure 1.3 Global CO2 emissions by sector for the year 2016 [4]

With this in mind, the need to change our approach to the production and consumption of energy if we want to counteract the accelerating climate change is clear. This need was already recognized by 195 countries, signatories of the Paris Agreement [5]. Furthermore, on a more local level of the European Union, the European Commission proposed in legislative package “Clean energy for all Europeans” a goal of at least 32% energy coming from renewable sources by 2030 [6]. And within the goals for sustainable development presented by the United Nations [7], the goal of “Clean and Affordable Energy” can be directly linked with the areas of electricity and heat.

The most oblivious way to achieve the climate goals within the electricity and heat sector is to switch from fossil fuels to renewable energy. But what other ways are there to decrease the harmful emissions? According to publication [8], there are four general groups of methods that can contribute to a reduction in those releases:

- Demand reduction,
- Efficiency improvement,
- Substitution of alternative fuels or energy source,
- Capture and storage of CO_2 emissions.

‘Efficiency improvement’ and ‘substitution of alternative fuels or energy source’ can be described as approaches that are most mature currently. The EU energy label [9] is informing the customers about the energy efficiency of their devices and goals set for renewable energy contribution towards national electricity mixes markets are a clear push towards those approaches. Regarding, the renewable electricity consumption goal - in 2016 already 17% of the energy consumed in EU-28 was coming from the renewable sources, which is on track to 20% goal for the year 2020 [10].

The Carbon Capture Sequestration and Storage (CCS) technology, while being continuously developed and presenting sufficiently high Technology Readiness Levels (TRLs), is not yet being deployed on a widespread commercial scale that would be able to counteract the CO_2 emissions [11].

Furthermore, the approach of demand reduction is being examined, however more in the short-term context of demand-supply balancing.

In the context of those measures, the electricity grid is experiencing more intermittent generation from the Renewable Energy Sources (RES) with changing trends in electricity consumption and generation related to the adoption of new technologies.

This brings challenges for the Distribution System Operators (DSOs), who need to start taking these new developments into account when planning their networks. However, it can also be an opportunity to introduce Demand Side Management (DSM), a concept in which consumers start adjusting their consumption in order to reduce their impact on the grid and, in turn, allow to accelerate the energy transition.

With those changes in mind, the DSOs start asking on how to adapt to the changing reality of consumers switching more of their energy demand towards electricity, taking a more active role in the electricity system (by becoming prosumers – consumers that also produce electricity), while dealing with more intermittent energy generation.

One of the important aspects of DSO operation is system planning. With the lifetime of the grid assets reaching decades, the need for their adequate dimensioning and utilization becomes of major importance. With this in mind, the question arises: "Can Demand Side Management be utilized in the process of grid planning and postpone grid asset replacement?".

However, in order to answer this question, first it is needed to know how much can be gained by utilizing residential side flexibility in electrical energy consumption.

1.2. Methodology

1.2.1. Research questions

The problem that this graduation project addresses is the <u>assessment of the benefit that demand side flexibility can bring to the DSO</u>. More specifically this is done within the settings of the Netherlands, for the needs of the DSO Enexis Netbeheer B.V. For this purpose, flexibility coming from households (DSM), photovoltaic panels, electric vehicles and electric heat solutions will be considered. With this in mind, the following research questions were formulated:

1) Which methods are available to activate customer flexibility and what would be their effect on the individual load?
   This question produces tasks mostly related to the analysis of various 'smart grid' pilots and literature research. The expected outcome would be an identification of method that would be efficient at the activation of flexibility – that is, would provide a sufficient amount of flexibility in a reliable way for acceptable cost and would be viable from both technical and legislative perspective. Furthermore, the effect of the found methods on the individual load would be compared.
2) According to the criteria stated in question 1, what would be the preferred way to model flexibility in the households for network planning purposes?
   Tasks related to a literature review of modelling approaches, conceptual work and modelling itself. The expected outcome would be the identification of the method to model household flexibility from the distribution network planning perspective, according to the criteria stated in question number 1 and the development of such a model.
3) What would be the optimal way to include flexibility in current stochastic load models of households used in Enexis' network planning tool?

Research question related to the previous one, as the identified way of modelling, should also be suitable for the use in the tool. For this reason, the expected outcome would be an identification of the optimal way to incorporate flexibility into Enexis' network planning tool and possibly implementation itself.

4) What would be the value of flexibility for the grid operator in a large-scale network assessment?
The tasks related to these research questions would be mostly related to the outcome of the 2nd question, where the results from the simulation with and without flexibility could be compared. Based on those simulations, calculations related to the benefits of investment deferral and costs of activation of flexibility would be made in order to assess the net benefit of flexibility for Enexis Netbeheer.

1.2.2. Structure of the thesis

Introduction, together with stated research questions is given in the 1st chapter. The remainder of this thesis is structured in the following way.

The 2nd chapter covers developments in the power sector – the main drivers of change to the traditional asset planning process and main opportunities for DSOs related to those changes. First, it covers changes in the way of power system operation, relevant for its planning, and describes new developments that are behind this change. Lastly, it introduces the concept of flexibility, its definition and classification, and finishes with describing the opportunities that it provides for the DSO.

The 3rd chapter answers the 1st research question of this thesis: "Which methods are available to activate customer flexibility and what would be their effects on the individual load?". This is done by introducing different flexibility activation methods, based on the literature research, and then comparing them.

The 4th chapter covers the 2nd research question by examining current approaches for modelling flexibility in the context of this thesis. Furthermore, assumption, challenges and approaches taken for this modelling are discussed. Finally, the developed model is presented and its results are examined. By doing so, the 3rd research question stated in this thesis is being answered.

The 5th chapter answers the 4th research question by assessing the savings that the DSO can achieve by employing flexibility to prevent or postpone network reinforcements. This value can then be compared with the possible costs of activation of flexibility from a given method.

This thesis concludes with the 6th chapter, which provides the reader with a summary of results, conclusions and recommendations for future work.

1.3. Datasets

For the purpose of this research, several datasets were used. Those are as follows:

- Household and new technology load profiles generated for the purpose of use for network planning within the doctoral research of Raoul Bernards. The methodology behind those can be further explored in his doctoral dissertation [12].
- Onderzoek Verplaatsingen in Nederland (OViN) data gathered for years 2015-2017. It details the commute data of people surveyed in the Netherlands. For the purpose of this thesis, this data was filtered to include only car trips. This data was further transformed to generate representative samples that were later used to simulate EV owners driving profiles (home

departure and arrival times, distance of the trip) [13]. The use of this data is further explained in Appendix IV: Fast EV profile generation.

- Enexis' network data and specific data related to asset loading – the current number of households connected to a given asset and future technology adoption ratios based on the research done in R. Bernards' research [14].

1.4. Enexis' Scenariotool

As one of the preferred outcomes of the thesis is an addition to a current tool that Enexis develops for short to mid-term network planning, the proposed method of modelling needed to be compatible with the aforementioned tool. Furthermore, this approach allowed for the examination of the flexibility impact on the distribution network on a larger scale.

The tool itself is used for examination of the impact of new technologies, on loading and voltage limits of DSO grid assets, and is an implementation of several of the models developed in [12]. Based on the historical adoption data and spatial socio-economic characteristics the future adoption ratios of new technologies are assessed with the help of linear regression models. Those adoption ratios have the "resolution" of a single network component and can be varied according to the national scenarios or custom values of national penetrations of these technologies. Moreover, within this research an approach for synthetization of realistic household, PV, EV and HP profiles was presented. Within this approach, it is possible to generate differing, but plausible, load profiles for aforementioned technologies. The Scenariotool is designed to be utilized for the timeframe of about 10-12 years into the future.

For more information about the methodology behind the Scenariotool itself, the reader should consult the information available in the dissertation "Smart planning: integration of statistical and stochastic methods in distribution network planning" [12] and a recent paper about the tool itself [15].

2. Developments in the power sector

2.1. Power system planning and operation

"Old way"

Throughout the past century, the power system evolved from the small autonomously operated "isles" into a singular entity strategically connected with the neighbouring nations' systems. This resulted in more reliable and efficient operation due to the introduction of redundancies and economics of scale. Within these systems, it was assumed that generators, connected to the higher voltage levels, will deliver electricity to consumers connected to low voltage levels. This resulted in an economically efficient system within which electricity was transmitted from high voltage to low voltage in a unidirectional flow.

This meant that grid planning was based mainly on the demand from the consumers of electricity. This demand was assessed using deterministic methods related to the peak demand. For the residential loads e.g. the Strand-Axelsson method was used [16]. In this method, the peak demand was assessed based on the annual energy usage of the households and simultaneity factors, which assumed that households use energy in a heterogeneous way – for different households, peaks in electricity consumption were not happening at exactly the same moment. This approach allowed for electricity distribution system planning for about 30 years in future [12]. It meant that all the assets were sized to function for at least 30 years before there was a need for their replacement. With the cost of a MV/LV transformer replacement being at 8 000 € (with substation expansion costs of about 20 000 –

40 000 €), and cost of procuring and laying a km of cable in the range of 100-120 thousand €, the decision about replacement needs to be well informed.

To put it into financial context, according to [17] in low voltage (LV) and medium voltage (MV) networks costs were mostly related to the location-demand (peak loading) rather than to location-energy (energy consumption). This means that proper forecasting, which in turn allow to adequately size assets, leads to more economically efficient operation.

Within this paradigm, the need for flexibility provision was put on generators. They needed to match their output to the momentary demand, which with they were able to do, as energy demand on the aggregate level was predictable and conventional generation has no volatility.

"New way"

However, with the recent developments on generation side and introduction of new technologies used by consumers the paradigm of the centralized system operated in top-down manner changes [18]. Adoption of new technologies (further discussed in the following sections) affects the electricity demand growth and challenges the unidirectional flow concept.

Introduction of renewable energy sources (RES) means that generation patterns are no longer so predictable and flexible. Generation from wind turbines and PV panels occurs only when the corresponding resource is available and such source is preferably operated at the maximal possible output. Furthermore, those sources are being connected not only to the HV but also to MV and LV grids. This means that certain parts of the grid start to experience bidirectional flows.

On the consumers' side adoption of PV panels means that they become prosumers – both consumers and producers of electricity. Also, the adoption of electric vehicles (EVs) and heat pumps (HP) results in higher increases in load than ones assumed in deterministic planning methods. The aforementioned technologies operate in specific ways, which in turn impact the grid in a different manner. It might be worth discussing these impacts, starting with photovoltaic panels.

2.2. New technologies

2.2.1. Photovoltaic panels

Currently, in the Netherlands households are allowed to install PV panels in a net-metering scheme. In this scheme, customers can lower their electricity bills based on the amount of energy produced. Furthermore, according to the new rules "Terugleversubsidie", coming into action in 2023, the repayment periods for residential or small business will be kept at maximum 7 years through government subsidies. The Dutch government noted that new rules have the purpose of further stimulation of the solar PV market and are offering a smooth transition for current PV owners in order to prevent so-called start-and-stop policy impact.

This set of policies resulted in the wide-spread adoption of PV panels in residential buildings, where some neighbourhoods have installed a significant number of PVs, as can be seen in Figure 2.1.

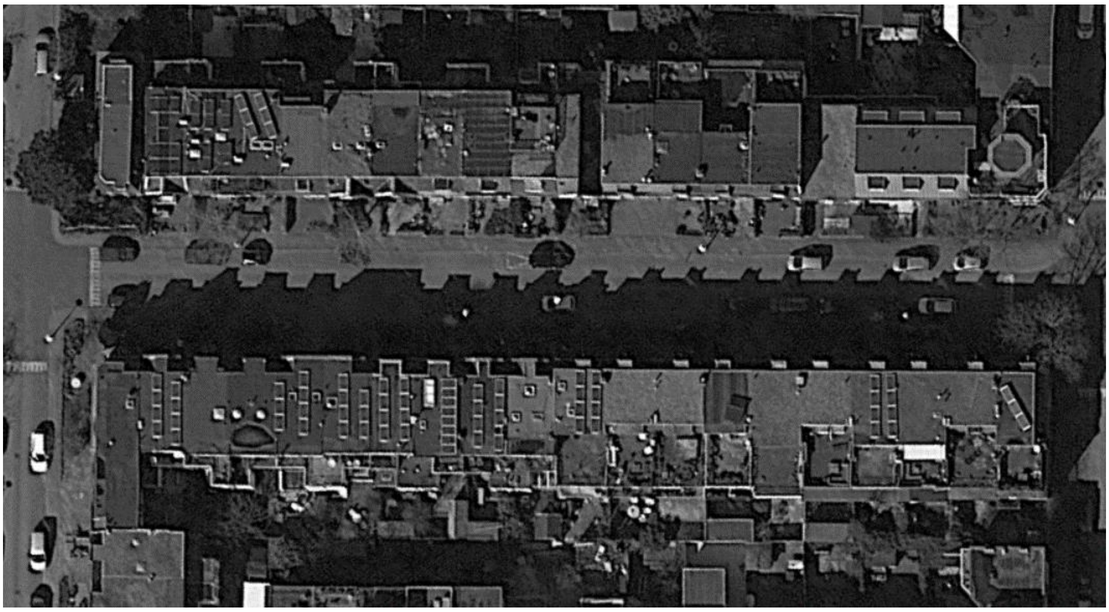

Figure 2.1 Bird-eye view for the neighbourhood in Amsterdam – Fahrenheitstraat neighbourhood [19]

On a national scale, it resulted in 524’000 household PV installations with a combined power of 1.67 GW by the end of the year 2017 [20]. The quite rapid growth of residential PV panel sector in the Netherlands can be seen in Figure 2.2.

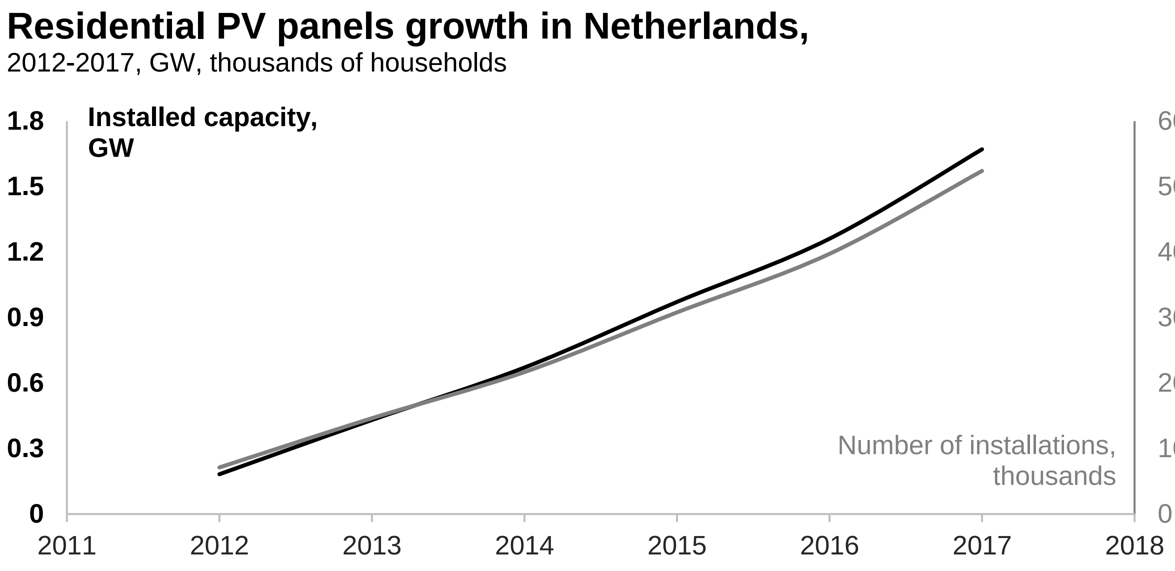

Figure 2.2 Growth of residential PV in the Netherlands, 2012-2017 [20]

Based on the simulations done in previous research [12] and within the Scenariotool itself, it became evident that, for certain assets, peaks from the reverse loading (feed-in of the energy into the grid by the prosumers) could be higher than those from normal consumption of energy.

This can be in big part attributed to the time of the day when PV peak occurs. To explain it, the energy produced by the PV system depends on a variety of factors: its power, efficiency, tilt angle, shading losses etc. However, after we take those factors into consideration, within the same neighbourhood all of the PV installations experience peak production at the very same moment. In this sense, their simultaneity factor can be extremely close to 1. This means that for purely PV generation assets would need to be sized to the sum of peak powers of all PV systems connected to it.

According to the consultations with supervisors [21], there are already neighbourhoods in the Netherlands were feed-in is visible on the MV/LV transformer level. And with higher penetration ratios, its effect can be more present due to the explained simultaneity.

Potentially, this can be solved by certain methods of flexibility activation that will be discussed in later sections. And PV systems are not the only new technology that can have a substantial effect.

2.2.2. Adoption of electric vehicles

While PV systems can have a significant impact on the reverse loading of assets, there are certain technologies that can cause a big increase in normal asset loading. One of those are EVs, with special emphasis on Battery Electric Vehicles (BEVs).

According to the Dutch government ambitions [22] in 2020, at least 10% of cars sold will have an electric powertrain and a plug. In 2025 this number is supposed to be 50% of all cars sold (and 30% of those will need to be BEVs). By 2030 all of the newly sold passenger cars are supposed to be zero-emission. While this number also includes hydrogen-powered cars, it should be safe to assume, that with current market trends, technology maturity and development of charging infrastructure, the majority of those zero-emission vehicles will be BEVs. The progress towards government target can already be seen – since the end of the year, 2015 number of BEVs grew by almost 500%, as seen in Figure 2.3.

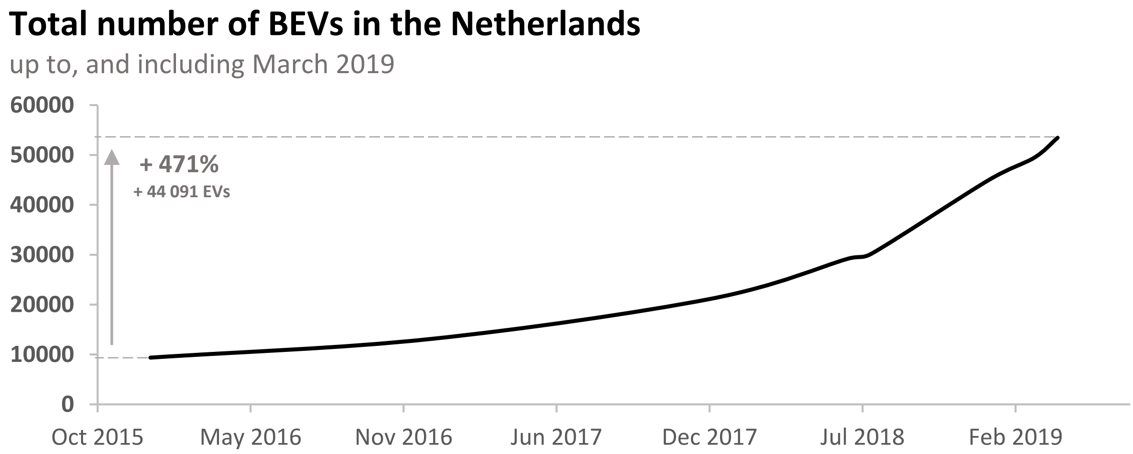

Figure 2.3 Total number of BEVs registered in the Netherlands [23]

Several studies [18], [24]–[28] identified EVs as a load that will play a significant role in the increased electricity consumption in the future. This can be again attributed to the simultaneity of arrival times and the coincidence of EV charging with the evening peak of electricity consumption. In order to explain that, first the standard residential profile must be presented. An example of one can be seen in Figure 2.4. Based on this figure the peak load between 17:00 and 18:00 can be clearly identified.

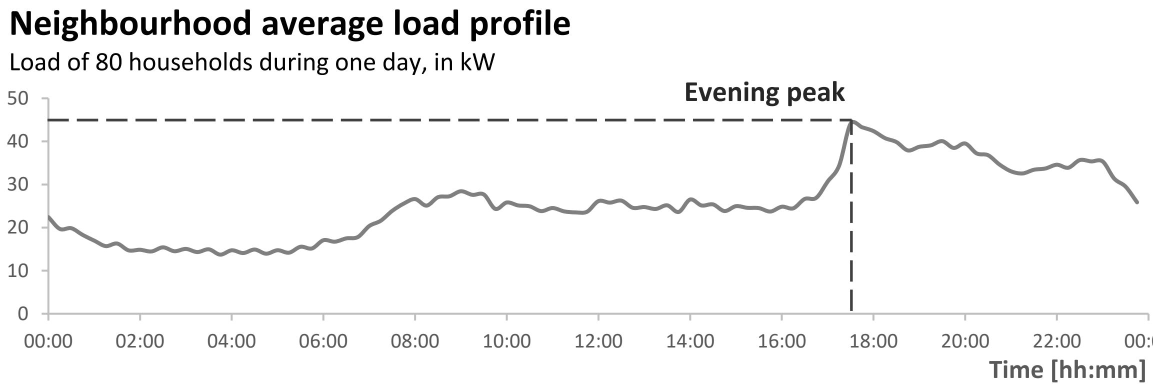

Figure 2.4 Example average load profile for the neighbourhood of 80 houses (3500 kWh)

The moment of rapid load growth leading to this peak can be attributed to residents coming back home after work. Following this thought, if those people come back in electric cars, it is likely that they will plug them in, in order to recharge batteries. This, in turn, will increase the strain on the grid assets, further reinforcing the impact of the evening peak. Furthermore, EVs are not the only technology that is resulting in higher electricity demand by households.

2.2.3. Adoption of electric heat technologies

With national plans of reducing reliance on the gas-based heating solutions, it is likely that the Netherlands will experience the wide-spread adoption of the Heat Pumps (HPs). This means that energy demand will switch from gas to the electricity. The need for clean heating was already defined in plans for the future [29], [30]. Furthermore, in some cases also electric boilers need to be taken into account – those are not as efficient as heat pumps but are sometimes required as a back-up or supplementary systems. Also, going away from gas most likely means higher use of electric cooking in households. This all together can lead to a visible increase in the energy and power demand by the households. To illustrate it, example profiles of a heat pump for a winter day can be seen in Figure 2.5. If we take into consideration that on the very cold days most heat pumps would be forced to use supplementary electrical heaters or electrical boilers, the impact on the load of the household can be quite severe.

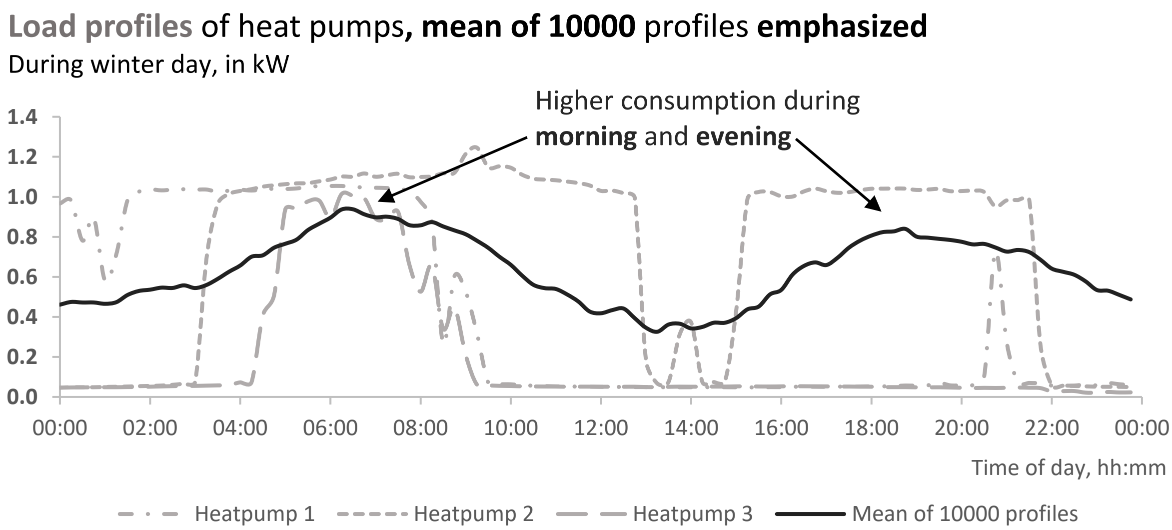

Figure 2.5 Example load profiles of heat pumps [12]

Going away from gas-based heating means that large energy streams will be converted to electricity. And again, the simultaneity can play a significant role in the concentration of the peaks – the control of heating devices is dependent on the indoor temperature and outside temperature. This means that most of the heating demand will likely occur when people are at home and when outside temperatures are low. While heat pumps themselves are recommended to be operated continuously with low energy consumption, in situations where the additional supply of heat is needed for e.g. domestic hot water, the impact of the system becomes more significant. Based on Figure 2.5, it appears that this demand occurs usually in mornings and evenings. This is likely to further intensify existing peaks.

In the end, the aforementioned technologies can strongly influence grid asset loading. Moreover, usually, there is a lower simultaneity between generation from PV panels and consumption by EVs and HPs. PV panels tend to produce energy predominantly during the day, while consumption of energy for HP and EV purposes happens in the mornings and evenings. This poses a question: is there a way to change those energy consumption patterns to reduce peak demand and supply values?

2.3. Flexibility

2.3.1. Introduction

Electrical energy, compared to the other energy mediums, has one quite distinctive characteristic – at any given moment in time, the amount of electricity generated needs to match consumption. This is mostly due to the fact that historically attempts at storing electrical energy in different mediums were problematic and/or expensive.

However, a new idea is gaining traction – why should it be only generators, that take care of this balance, when also consumers can adapt their energy consumption. From this, the concept of demand-side management grew. From the DSO perspective, the main issues related to the new loads and residential generation is current congestion and under/overvoltage. As the later is also related to the former it might be worth keeping the focus on current. In this sense, the load can be imagined as a wheel that tries to rotate at the speed corresponding to momentary demand (or changes direction, when a household produces more energy from PVs than it uses). With this metaphor, flexibility can be imagined as a smaller wheel that allows for changing the rotational speed (energy demand production) of the load wheel, preventing it from spinning too fast and creating congestions. This can be visualized in Figure 2.6.

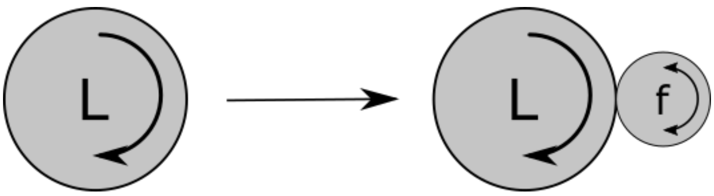

Figure 2.6 Flexibility as a modification of demand momentum

This further plays into the metaphor of the flexibility at a system level, where it is used to balance the electricity system. In this sense, the system is the biggest wheel, which needs to rotate with a stable frequency of 50 Hz. Loads and producers are the smaller wheels that counteract themselves in order to keep the system stable. In this in this metaphor flexibility can be used to balance those forces – affecting both generation (as in conventional systems) and demand (with the concept of demand-side management). This is shown in Figure 2.7.

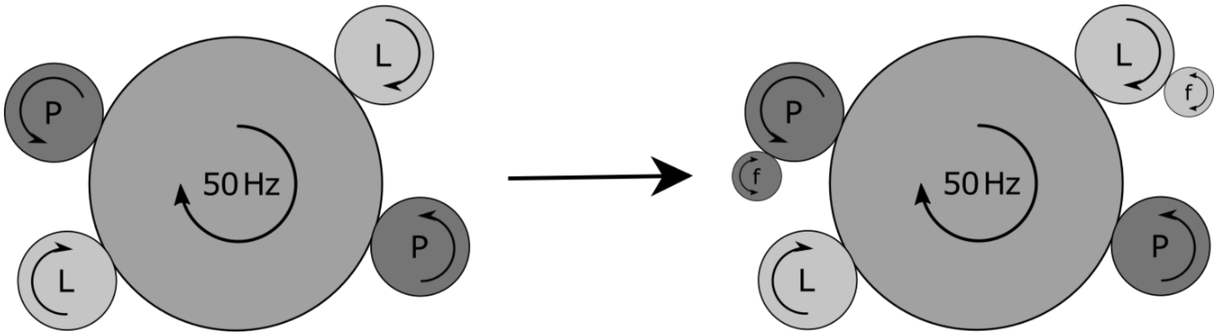

Figure 2.7 Electricity system as a wheel, with sources 'P' accelerating it, loads 'L' deaccelerating and the flexibility 'f' affecting both sources and loads.

Official definitions are of course more complicated, but Figure 2.6 and Figure 2.7 present the basic idea behind flexibility.

It needs to be mentioned that while it is interesting to illustrate and show all the connections, the flexibility for system balancing is out of the scope of this thesis.

When going further into the topic of flexibility, there is an important distinction between its types, related to the method of its activation, that should be explained. This difference is between explicit and implicit flexibility.

2.3.2. Explicit flexibility

Explicit flexibility, following information in the literature, is the flexibility that is "committed, dispatchable flexibility that can be traded (similar to generation flexibility) on the different energy markets (wholesale, balancing, system support and reserves markets)" [31]. Schemes that facilitate this type of flexibility, often also include an aggregator – a party that manages flexible resource activation. Explicit flexibility is often referred to as incentive-driven – this means that parties providing it are incentivized in ways other than simply cheaper electricity prices. This can be realized by e.g. aggregator being able to control certain high-load device of a consumer (washing machine, dishwasher, dryer) and delay or pause its operation within agreed-upon limits. The consumer then is usually compensated by for example a flat rate per month.

2.3.3. Implicit flexibility

And following the definition from the same source, implicit flexibility is "reaction of a consumer to price signals" [31]. As this is usually coupled with the price of energy, implicit flexibility is often referred to as price-based. In this scheme, the final customers are responsible for adapting their behaviour, in this context electricity consumption. A price signal can be used to encourage customers to shift their energy use from high demand periods to lower demand periods by for example time-of-use (TOU) tariffs. Moreover, such tariff could put a higher price on energy consumption in the e.g. evening period (in order to reduce the impact of evening peak, shown in Figure 2.4 and lower in the other times of the day.

2.3.4. Flexibility from DSO point of view

Different parties can be interested in flexibility – Transmission Network Operators (TSOs) or Balance Responsible Parties (BRPs) for the purposes of system balancing or portfolio optimization. This thesis considers flexibility from the perspective of DSO. And from it, flexibility can be a potential solution for decreasing the impact that new technologies have on the grid and can allow for better, more efficient, utilization of DSOs assets [32]–[34].

Within the evaluated research, certain publications consider the system-wide impact of flexibility [29], [35], look into the barriers that prevent more widespread adoption of it [36] and try to identify different sources for its provision [35], [37]. Furthermore, many definitions are being introduced [34]–[38], but for the purpose of this work, one presented by [34], with slight modifications, was taken:

"On an individual level, flexibility is the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. The parameters used to characterize flexibility in electricity include: the amount of power modulation, the duration, the response time, the location, etc."

This definition was chosen because it addresses the individual level, which matches the DSOs focus on the MV and LV levels of the system, instead of the system-wide approach (as presented in [35]) which would be more relevant for the TSO.

Furthermore, it should be noted that if flexibility is procured with the purpose of grid investment deferral some criteria should be further emphasized:

- Reliability (Certainty) – ability to provide flexibility in a consistent manner in a specified location.
- Continuity – might be considered as reliability, but from the perspective of asset lifespan. As DSOs size their assets for at least 20 to 30 years into the future, the examined way to activate flexibility should be able to do so reliably for a certain number of years into the future and preferably being able to scale in a similar manner.

From the perspective of this graduation project, the potential of flexibility for current grid congestion will be the main focus. This implies a high focus on the location where flexibility is needed, to the granularity of a single grid component e.g. transformer or (part of) a cable. This approach also implies a high focus on reliability and continuity. Moreover, it should be also be taken into account that grid assets can be overloaded by a certain percentage over a certain time (e.g. transformers by 30% over 2 hours [26]). However, often overloading or going above said limits can decrease the lifespan of an asset. According to the same paper [26], the cost of overloading increase exponentially with the transformer loading. This means that flexibility would need to be provided in a rather reliable and consistent way, especially when demand grows in the future.

Besides the aforementioned requirements, other criteria exist. As described in the 1st research question, a method used for the activation would provide a <u>sufficient</u> amount of flexibility in a <u>reliable</u> manner, at an <u>acceptable cost</u>. Furthermore, it would be <u>socially acceptable</u> and <u>viable from a technical</u> and <u>legislative</u> perspective. This requires a more detailed distinction between activation methods and further research into how they fulfil the aforementioned criteria.

3. Methods to provide flexibility

3.1. Introduction

Flexibility can be activated by using different methods. The previous chapter introduced a distinction between implicit and explicit flexibility. The concept of different solutions used to change electricity consumption patterns can be explored in this chapter.

Based on the literature research [33], [36], [39] alternative classification can be added beside purely implicit and explicit methods. The reasoning behind this action is that other categories with different incentives, degree of freedom in use and actors that activate them. Those categories include connection agreement, technical and rules-based solutions. This differentiation can be seen in Figure 3.1.

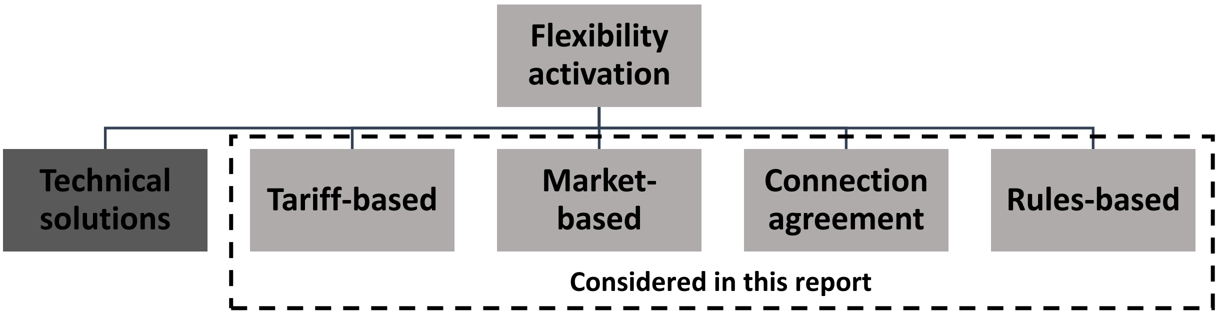

Figure 3.1 Flexibility classification by method of activation

Technical solutions are characterized by the fact that they are “invisible” to the grid users. This means that they are not introducing any inconveniences to them and are realized mostly at the DSO operation level. Examples of those can be e.g. grid-side battery storage, transformer on-load tap changers or grid reconfiguration. However, since according to industry reports [33] technical solutions come before other and since they are implemented on the grid level, they are not relevant when it comes to the activation of flexibility from households. Therefore, they will not be discussed further in this report.

This chapter will present the remaining activation schemes with, where possible, examples from current implementations or pilot projects. However, it needs to be mentioned that in the explored literature there is no convention yet that would allow for quantitative research and comparison between different implementations or pilots. For this reason, the comparison will be done in a qualitative manner. The five-point Likert scale will be used, similar as in [40].

Furthermore, it needs to be mentioned that due to the scope of the thesis following sections will be written, where possible, with a focus on residential side flexibility activation for the applications of DSO.

3.2. Tariff-based

When it comes to the households, tariff-based solutions were so far the most prevalent ones. Based on the information from the literature [41], for most of the European countries, the majority of tariff cost is based on the volume of energy consumed.

But there are more variables when it comes to the tariff design. According to [33] tariffs can be structured with the following elements:

- Basis:
  - Capacity – based on the installed or used capacity (connection to the network).
  - Energy – related to the consumption of energy, typically in kWh, during a set period.
- Timing:
  - Fixed timing – within the time period specified in the contract there can be a different cost for certain time of the day or week. This time does not vary from day to day (or week to week if it is a case). E.g. peak tariff with higher costs from 17 till 20.
  - Dynamic – rate is tied to the current state of network, area or market e.g. real-time pricing.
- Direction:
  - Consumption – the cost of energy consumption.
  - Production – rate for produced energy.

- Location:
    - Per DSO area – applicable for the certain DSO(s) operating area.
    - Locational tariff – related to the geographical (nodal or zonal) location of the customer.[1]

The final tariff can be a combination of the aforementioned elements. However, it needs to be emphasized that tariffs should be designed in a way that is easy to understand for the average customer. More understandable designs allow customers to more effectively utilize it (effects are more likely to be in line with the goal behind the design).

In the context of flexibility, tariffs should be designed in a way that stimulates its development. It should be mentioned that industry reports [33] give an example of net-metering as flexibility blocking scheme. This is mostly related to the period for which generation and consumption are compared. One with a length of a year produces absolutely no incentive for prosumers to match production to demand and vice versa. This comes in contrast with current policies in the Netherlands, where the net-metering scheme is used.

Nevertheless, as was mentioned in section 2.1 the majority of the cost of assets in LV is related to the peak power, not energy consumption. Thus, the idea of capacity (power-based) tariffs becomes more popular. Costs of this tariff better reflect usage of the network. An example of such tariff, with symmetrical component (in the form of a fine for introducing too much power into the grid), can be seen in Figure 3.2.

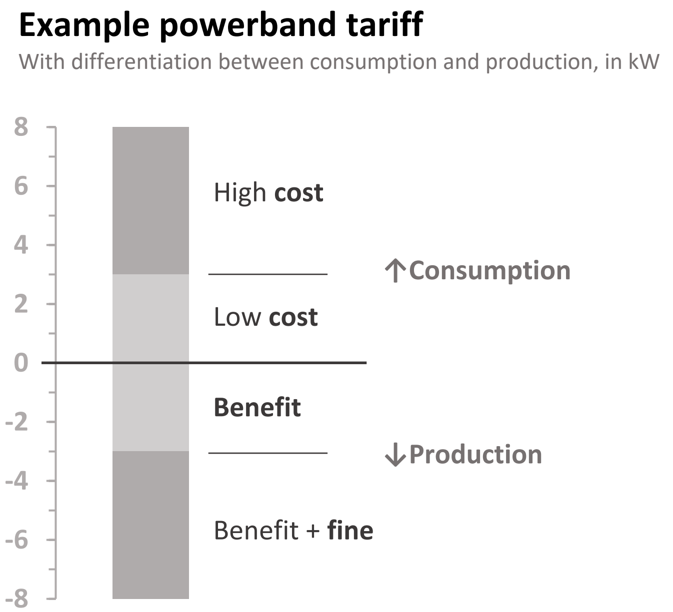

Figure 3.2 Example of powerband tariff

Power-based tariffs were generally found as an effective measure to reduce peak loads in performed studies. Research performed with the German market in mind [43] discovered that an additional power component (in different forms, e.g. higher constant cost paid above certain consumption limit, the higher price of electricity above certain momentary power withdrawal or with price component

[1] It should be mentioned that locational pricing can severely affect the 'fairness' and 'non-discriminatory' criteria for tariff evaluation. Due to that locational tariffs might prove to implement. Nevertheless, [42] suggests that locational pricing might be necessary with current trends of local energy communities, peer-to-peer trading, even though regulators (with some exceptions) are not willing to switch from lower risk socialized pricing models.

related to daily consumption peak) generally resulted in a reduction of peak demand. The same research concluded that the inclusion of real-time pricing (RTP) in the tariffs resulted in lower energy consumption, but higher peak demand. However, it should be noted that the presented research is based on the simulation rather than a real-life (pilot) project. Furthermore, the presented tariffs were rather complex and would require significant automation of household loads – which would mean that more time would be required for widespread adoption. Moreover, the focus of the work was on the power and energy use optimization with a PV system, batteries and dynamic loads[2].

Another research, this time in the Flemish context, was presented in [44]. It claims that with the introduction of smart metering it becomes possible to introduce more complex tariffs (including one based on the power component). It concludes that tariffs with load components (power) are effective in the reduction of the peak loading and specifically tariff that contains fixed energy and power components presented the best case for customers that self-generate power and have storage capabilities.

Furthermore, in the PDEng thesis of A. Van Amstel [28] the approach of Critical Peak Pricing (CPP), among others, was examined with a focus on the EV charging at residential and public stations (11 and 22 kW capability). In this approach, during the periods of expected high demand, a higher energy price was applied. However, with CPP applied to fixed time periods there exists a risk that consumers would avoid the peak price and start electricity usage at the moment when lower price period comes into effect. This resulted in a new peak, just after peak period finishes, that was overloading simulated transformers. This result was obtained for the case where the spot market price is not considered. When CPP was further coupled with the spot market prices the overloading was reduced, with the drawback of the high cost to the end users of energy.

In a series of research projects performed at Finnish universities [45]–[48], power-based distribution tariffs were examined specifically from the perspective of the DSO. Their findings can be summed up to following: demand response driven by market actors different than DSO (aggregators, energy retailers) is likely to result in increased loading of the DSO assets if special precautions are not taken before; purely power-based tariffs can result in increased asset loading if only a small subset of customers will react to them; combining power with spot pricing is effective in the mitigation of the system peaks; power-based tariffs limit the potential of demand response; power-based tariffs are likely to become more effective with new high demand loads joining the grid (e.g. EVs); such tariffs incentivize residential energy storage. Among different approaches to power-based tariffs following were presented [46]:

- Power Tariff – in this case, the tariff is based on the basic charge, energy charge and highest power measured during the billing period.
- Threshold Power Tariff – this tariff consists of a basic charge, energy charge and power charge (€/kW). The latter is only applied if the household exceeds a certain threshold.
- Power Limit Tariff (subscribed power) – a power charge based on the pre-ordered capacity. If this capacity is exceeded customers are forced to pay a fine or need to subscribe to the higher tariff.
- Step Tariff – this tariff consists of a basic charge and two energy charges. The first one applies to lower power consumption (below band/threshold) and later to higher power consumption (above band/threshold).

[2] Devices that allow a shift in energy demand during a specific time period without major energy losses.

It needs to be mentioned that those Finnish studies were mostly conducted using simulations and assumptions and were not tested in pilot projects.

A further study examining the effect of power tariff (in a format similar to explained above, but without basic charge) was conducted in Norway [49]. According to the study results, all participants taking part in the pilot experienced a significant reduction in used energy and lower power peaks. According to the authors, this tariff promoted conscious usage of electricity – local households started looking into improving the efficiency of their energy use.

It should also be mentioned that presented studies suggest tariff design in a way that would keep the DSO revenues at a similar level as with the previous tariff. However, they are not taking into account the possibility of behaviour change [46] or use predefined responses of customers [47]. In case such tariff would be introduced, it is recommended to perform pilot studies to examine possible behaviour in order to not produce a significant change to the DSO revenues.

As a way to summarize the findings of this section in Table 3.1, a comparison of most common tariff types can be seen. It was adapted from a paper [50]. When considering only peak reduction, the capacity-based tariff appears as the best choice. However, when we take into account impact on energy consumption and result from presented research and pilots (that if an only small subset of users reacts to tariff signals asset loading might actually increase), the two-part tariff becomes more enticing despite the higher complexity.

Table 3.1 Network tariff type comparison, adapted from [50]

Network tariff type	Fixed volumetric	Capacity-based	Time-of-Use volumetric	Two-part tariff
Examples	€/kWh	€/kW	Peak pricing, RTP	€/kW + €/kWh
Incentive	Consumption reduction, regardless of the time of consumption	Reduced peak usage, shift to off-peak hours	Reduced consumption during peak hours, shift to off-peak hours	Reduced peak usage, Reduced consumption during peak hours, shift to off-peak hours
Impact on energy consumption	Medium-High, worse than in case of ToU tariffs	Medium (Medium-High for ToU capacity tariffs)	Medium-High	Medium-High
Impact on network cost (peak loading)	Low	High	High	High
Regulatory trade-off criteria*	+ Intelligibility / Acceptability – Economic efficiency – Cost reflectiveness – Revenue adequacy (for DSOs)	+ Intelligibility / Acceptability + Economic efficiency + Cost reflectiveness + Revenue adequacy	– Higher tariff complexity + Economic efficiency + Cost reflectiveness – Revenue adequacy	– Higher tariff complexity + Economic efficiency + Cost reflectiveness + Revenue adequacy

** pros are shown with '+' and cons with '-'*

According to the information above it appears that two-part tariff appears to be the best overall in most of the categories, with an assumption of equal evaluation across all of them. Only in the regulatory trade-off criterion it didn't perform on par with the best, due to the relatively higher complexity. Nevertheless, the 2nd contender, purely capacity-based tariff presented somewhat worse performance when it comes to the impact on energy consumption.

However, tariffs are not the only mechanism to incentivize the flexibility of electricity usage – another popular concept is a market-based solution.

3.3. Market-based

When the topic of flexibility market is brought up, it is commonly associated with an aggregator-based approach. This is used to assure enough capacity and controllability is provided – something that individual distributed resources lack [36]. In this approach the aggregator "pools" the distributed flexibility into a single system resource. So far, most of the aggregator-based models were applied to the system-wide balancing. In this case, the focus was not on the location of the provided resource, but rather on quantity and reliability. However, the proposed market-based solution needs to be available at a very local level to be viable for DSO purposes.

Such concept of local flexibility markets is being explored in research papers [39], [51], [52], often with managing grid congestion and local self-reliance in mind. Multiple ways of flexibility market organization were presented, including auctions, peer-to-peer transactions and predefined contracts. However, in case of this work the exact organization of the markets will not be the focus, due to the number of different schemes that are being proposed and complexity of some. The focus would be rather on the general overview of more promising approaches and pilot project results.

The most common organization includes several parties taking part in flexibility schemes. First are the households, businesses (also companies managing charging points for EVs) that provide flexibility resource. Due to the already mentioned reasons they are being pooled by the aggregator who then can offer flexibility to different stakeholders: Balance Responsible Parties (BRPs), for portfolio balancing; DSOs, for solving congestion and other technical problems; and Transmission System Operators (TSOs), for balancing services [26], [28]. An example of the local flexibility market parties with flows of power, flexibility and cash can be seen in Figure 3.3.

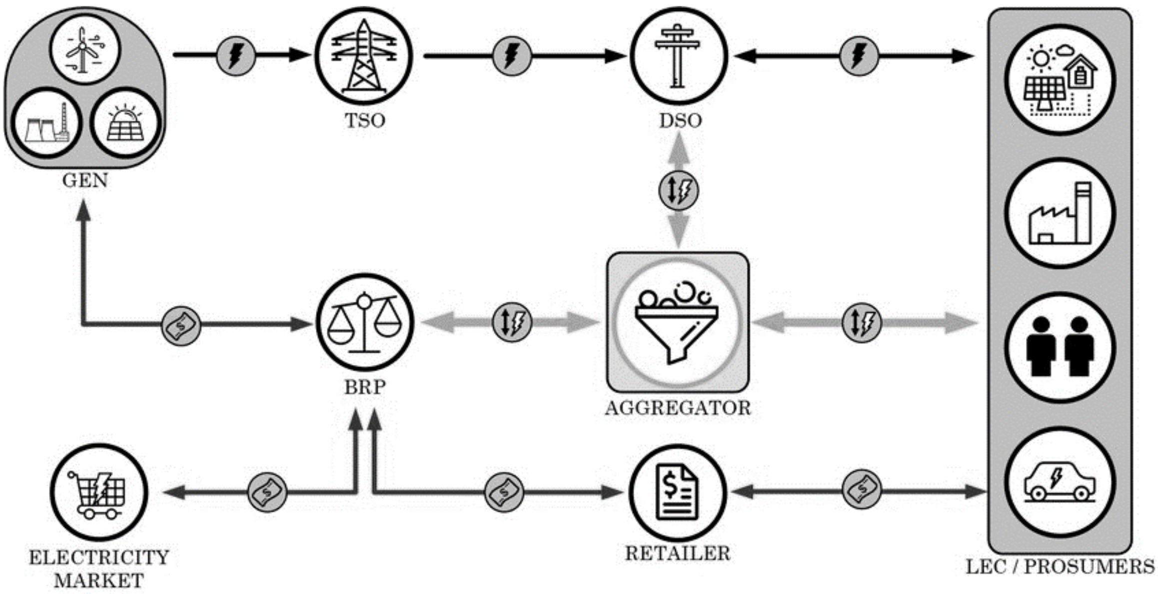

Figure 3.3 Local flexibility market overview [39]

Due to the fact that there are multiple parties that can be interested in procuring flexibility, certain precautions should be taken to prevent an aggregator from pitting them against each other and market gaming. One of the ideas proposed to prevent DSO competition with TSO or BRP (cases where flexibility activation by the latter two would cause technical problems in the distribution network) was the traffic light concept. Within it, the market can operate freely as long as there are no signs that the grid might be under threat. In the green state, the market operates freely with BRPs having priority of participation. In case that the threat to the grid can occur in the near future, the DSO is allowed to join the market and his requests have priority (yellow state). When the grid experiences a technical problem (saturation/congestion) the DSO can take direct control over the flexibility sources in order to stabilise the grid (red state). However, implementation of this concept would require better cooperation between all the parties involved (TSO, DSO, BRP, aggregator) and would require extensive information exchange on the line TSO-DSO. Furthermore, such an approach might require certain arbitrage/supervision in order to resolve the conflicts related to the need for yellow and red states.

Another concept for flexibility was presented in [53]. In this case, flexibility was procured through "Contract for deferral scheme" (CDS) in which DSOs can enter into a contract with parties which would offer available capacity when needed. It needs to be mentioned that this is a broader scheme that doesn't focus purely on flexibility but also considers other products related to investment deferral in the grid, e.g. energy efficiency.

As goes for real-life implementations, there were already several pilot projects performed in Dutch and Flemish context, that can be discussed. The PowerMatching City pilot has shown that market implementation is possible and the PowerMatcher algorithm was able to connect demand with supply [40]. It was shown that the semi-automated system for the procurement of flexibility is preferred over manual one by residents. However, the fair distribution of benefits between the consumers, DSO and aggregator proved problematic. In the Energiekoplopers pilot [40] the Universal Smart Energy Framework (USEF) was used in order to facilitate a market within which flexibility would be offered to the DSO and BRP. The main outcome was that a DSO can use a flexibility market for congestion management, however, it didn't prevent overloading completely. During the pilot it was shown that on average $^{2}/_{3}$ of purchased electricity was delivered – this value was explained by ICT reliability and DSO-BRP conflicts of interest. One of the limitations of this pilot was that the role of aggregator, BRP and supplier were performed by a single entity – this could have led to limited market and simplified, compared to the more real-life implementation, settlement and renumeration processes between all parties.

One of the interesting pilot projects, that already concluded, is LINEAR that took place in Belgium between the years 2009 and 2014 [24]. It examined the possibility for flexibility gains from white goods (e.g. washing machines, dryers, dishwashers etc.), electric hot water buffers and EVs. This pilot prioritized user comfort over the technical objective. An interesting outcome of the project was seeming low reliability of the 'smart' scheduling of devices – in quite many cases this mechanism was prone to failure. It further suggested that the potential for an increase in loading was much higher than for decrease. While it might be beneficial on the system level when trying to match intermittent generation with demand, from the perspective of the DSO it can present a threat to a network. If a significant part of households connected to the same LV grid would receive a signal to simultaneously increase their consumption, it would likely result in grid overload. This insight should emphasize that DSO participation in the market (preferentially in a scheme similar to a traffic light concept) is necessary and their input should be carefully taken into consideration when establishing flexibility markets and their regulation.

While procurement of flexibility on the market presents an opportunity for an efficient mechanism with self-regulated pricing for multiple stakeholders, it is not yet mature enough in all the areas that would be of interest to DSO. Current implementations are rather focused on the Virtual Power Plants (VPPs) for portfolio balancing and Frequency Response Regulation. Due to that the exact location of the flexibility sources in the grid is not that important – and for DSOs purposes, this would require change. Furthermore, those programmes tend to be more focused on industrial sites and housing projects rather than single houses (with some exceptions). However, from the perspective of the DSO and with focus on residential sources the need for widespread adoption and exact location of resource arises. This includes challenges related to the Information and Communication Technology (ICT), conflicts between different parties interested in the use of flexibility. Moreover, depending on the regulation that will be implemented and "freedom" of the market settlement process and cooperation with multiple aggregators operating in the same area can introduce further obstacles. While these barriers can be overcome in the long term, a shorter-term approach might require more control from the DSO side, which could be realized through e.g. the connection agreement solution.

3.4. Connection agreement

In the category of connection agreement solutions, examples can be given mostly by variable network access or flexible connection agreement. Both of those have the potential for flexibility procurement [33]. In these approaches, the consumer doesn't have a firm connection to the grid (possible interruption in electricity delivery) or the connection size is varied. While the former solution is possible only for microgrids and prosumers that can be self-sufficient for certain periods of time, the latter can be seen in a similar way as power tariff, but with less freedom to consume above the limit. From the residential perspective, the former (lower reliability of energy supply) would be most likely unacceptable, however, a variable connection size might be possible. An example of such variable connection capacity can be seen in Figure 3.4 – in this case, there exists a period of reduced capacity and for the rest of the day customers are able to utilize their connection up to full capacity. Such an approach might be beneficial when it comes to the reduction of grid peak loading. Right now, pilots are taking place to test this family of approaches.

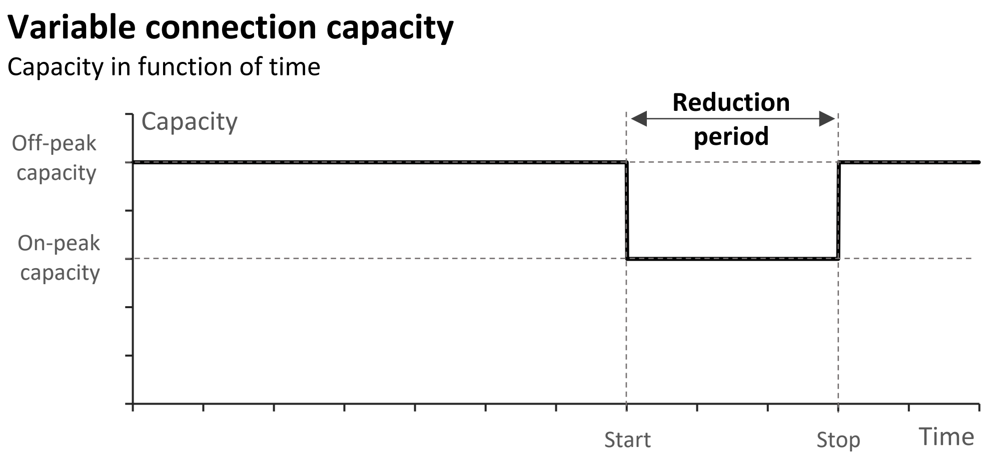

Figure 3.4 Variable connection capacity visualization, adapted from [28]

In M. van Amstel's PDEng thesis [28] variable connection capacity approach was simulated by means of on- and off-peak variance in capacity applied towards EV chargers. In this approach, several values of on-peak capacity were tested. In the case where energy cost was not tied to the spot market, more aggressive restrictions in on-peak period lead to peaks starting just after the reduction period was finished, because synchronized consumption from all restricted users starting right when the off-peak period begins. This observation is in line with the results for the CPP tariff, where fixed step change in pricing resulted in the introduction of new peaks. However, if the energy price was tied with spot markets, in most situations overloading was prevented. Furthermore, it was remarked that "implementation of a variable connection capacity with a low capacity during the restriction period is not feasible for the household while this would mean that during the restriction period the household cannot use non-flexible appliances" [28]. This means that the threshold cannot be set too aggressively, otherwise, it could prevent proper work of non-smart devices. This means that preferably all the household appliances would be 'smart', or household would have a battery system capable of overcoming this limitation. While interesting, either solution is unlikely to be widely implemented in short- to mid-term.

A similar approach towards variable connection capacity was taken in the FlexPower pilot project in Amsterdam [54]. In this project, a variable connection capacity was also applied to the EV charging stations. The exact limits to the charging power were dynamically determined by the network loading during peak times established between 7 am and 9 am in the morning and between 5 pm and 8 pm in the evening. Based on the released materials it appears that congestion in the local grid was reduced, however, the exact numbers were not shared. Interestingly, among the shared information it was included that for 86.5% EV charging sessions, the time needed to fill the batteries actually decreased (as the chargers were able to supply more power outside of the peak periods).

Furthermore, the Interflex project plans to test both fixed and dynamic variable connection capacity approaches, however as of the times of writing this report the results were not yet available. For more complete information it might be worth to consult those after they will become public [55].

To sum up the findings, it appears that variable connection size solutions present an opportunity for activating flexibility for grid congestion reduction as they appear to be able to effectively and reliably procure required resource. However, their application to the residential loads might prove problematic as it would require significant investments in ICT and solutions that would be able to limit the connection size. There is the possibility of using a solution that would not limit drawn power but would register an event when it happens. This event could then result in fees for the consumer which exceeded his capacity, however, such design brings it very close to some tariff-based solutions and removes the main benefit of variable connection size – reliability of load reduction. In general, a variable connection size seems to be much more suitable for the applications seen in discussed projects – public charging posts for EVs.

It needs to be stressed out that in this thesis variable connection capacity is considered as a 'hard' limit that customer cannot physically exceed. Otherwise, if the financial disincentivization approach is taken it can be considered as a tariff approach. Then it would resemble power limit tariff if the charge for connection size is applied based on maximal power draw within the specified period, or threshold power tariff, if the customer pays fine or is charged more for energy consumption above the limit.

Finally, the last type of approach towards the activation of flexibility can be discussed. This type is the most direct one from the side of DSO, leaving little freedom for the consumers. It can be described as rules-based.

3.5. Rules-based

According to [33], rules-based solutions are compulsory rules in network codes and regulations that impose technical requirements for flexibility. Among others, curtailment can be used as an example – in this scheme, the users of the grid are outright forbidden from exceeding their allowed capacity. In this sense, those actions can be implemented in the flexibility market in the form of a red state from the traffic light concept. In that case, existing regulations and rules would allow DSOs to take over control in specific situations. Another approach beside the mentioned two could be implemented towards EV charging – direct control of it by the DSO for grid needs (within certain boundaries).

While curtailment is an effective option, it could be met with low social acceptance as it forces behaviour onto the customer. Moreover, some publications claim that rules-based methods should be only used as a last resort [33] as they represent market failure. However, in certain situations where marginal consumption or production costs of the resource are nearing zero, as in the case of PV panels, it might be required approach. To elaborate on the example – for people that already have PV panels reduction in the fees that they receive for energy production might be not enough to convince them to invest into battery storage or change their behaviour enough to achieve higher usage of self-produced energy. In such a scenario, they might change their approach only when the cost of storage would allow them to more effectively recover PV cost or they would be charged for impacting the grid. And that is only assuming that such people would present good economic rationality. In this situation, curtailment could be the most effective approach from the perspective of DSO. However, it needs to be mentioned that this description closely resembles a variable connection capacity approach with a symmetrical band for the production – the main difference is that curtailment in this section is only applied to the energy production. Nevertheless, in further research projects, other impacts of such solution should be taken into account – remuneration for the lost production, how it would affect the future adoption of technology etc.

An argument for considering curtailment of PV production might be found in the results of FLEXNET project [56]. In its results, the Dutch DSO Liander claims that PV curtailment would result in a net benefit of €150 million for DSOs (already with the remuneration costs included) compared to the traditional grid reinforcement.

The second approach within the category of rules-based methods would be direct control – loads controlled by DSO. This approach was examined in [28] and while it completely preventing overloading it also left no choice for the customers. Furthermore, it resulted in an increased number of unfinished charging sessions for EVs. The argument against this approach can be brought up, as it most likely limits flexibility available to the TSO and BRP.

While rules-based solutions are able to provide flexibility in the most effective and reliable way, they might be unacceptable due to certain reasons. They limit freedom of choice for customer, in this context, they present low social acceptance and would require extensive legislation to introduce. They would require significant investments into the ICT for load control. They might severely limit flexibility available for purposes of different stakeholders. Nevertheless, due to their effectiveness, they might be considered in certain applications. The case where flexibility would be procured through the market with a traffic light approach can be given as an example. In this case, DSO would use direct control approach only when it would be absolutely needed and in other cases, the market would be allowed to operate freely.

3.6. Benchmark/comparison

In order to compare the presented approaches, criteria for this examination need to be established. In previous chapters, the ideas of sufficiency, reliability, cost, social acceptability, together with technical and legislative viability were introduced. Furthermore, the focus was put on reliability, which also includes a continuity criterium. This examination was done from the perspective of the DSO.

The criterion of sufficiency describes whether a given method is able to provide enough flexibility to prevent problems in the grid. This criterion examines if a given method is able to procure the adequate amount of flexibility in the first place, before examining how reliable and consistent it is.

The criterion of reliability describes how consistent a given method is in activation of flexibility – while overloading events can initially happen only during few days per year, it can be expected that a degree of grid congestion will increase in time if the same assets are kept. This would mean that a sufficient amount of flexibility needs to be provided each time.

The criterion of the cost represents the effect that a given activation method might have on the DSO revenue, preferably taking into account reduced cost for new assets. It can be also worded as cost reflectiveness – how accurately given method is able to represent real costs to the network operator. This is very important when we consider that the majority of costs for DSO come from location-demand (peak loading) rather than location-energy (energy consumption) [17].

The main factor influencing the acceptance of a given scheme would most likely be price. However, based on the fact that it is problematic to predict one before the introduction of the scheme, with its exact parameters, the evaluation of the effect of this factor might be not possible. Instead, social acceptability was examined by asking whether the method is voluntary and how much it affects user comfort. Moreover, the methods that would be more understandable and would offer predictable revenues were preferred.

Technical viability is characterized by the maturity of technology required to activate and control flexibility. Furthermore, ICT complication would negatively affect the score in this category.

The criterion of legal viability represents a degree of changes that need to be made to the regulatory framework. Moreover, it would consider if the tariff is 'non-discriminatory' and 'equal' for the customers [57].

The comparison can be seen in Table 3.2. It should be noted that it was done by the author as objectively as possible, however, the fact that this is qualitative comparison might mean that certain biases could have been introduced.

Table 3.2 Comparison of flexibility activation methods, ++ is the best score, while -- is the worst.

	Tariff-based (mostly power-based)	**Market-based**	**Variable connection size**	**Rules-based**
Sufficiency	+/-	+/-	+	++
Reliability	+/-	+	+	++
Cost	+	+/-	+	+/-
Social acceptance	+	+	-	--
Tech. viability	+	+/-	--	-
Legal viability	+	+/-	+/-	+/-

For the criterion of sufficiency, the rules-based method was given the highest score as DSOs direct control over the load would most likely mean that available flexibility could be fully utilized. Similar, the variable connection capacity could be configured in a way that would make the event of overloading highly unlikely. However, it lacks the level of control that a rules-based solution can provide. In the case of tariff and market-based approaches, sufficiency suffers due to the fact that market participation would most likely be voluntary – it would require wide-spread participation to allow for enough flexibility resource to be available. And in tariff scheme customers would have a choice of adhering to price signals or not.

When it comes to reliability, the rules-based solution gets the best score again due to the fact that DSO has direct control over it, consumers have likely minimal impact on the decision process of its activation. Similarly, variable connection size presents good opportunity due to the compulsory provision of flexibility. In case of a market-based approach reliability should still be high – consumers would be discouraged from not delivering contracted resource by means of a fine. This should be enough of incentive to assure reliability. In the case of tariff-based solution reliability is lower – much depends on the design of the tariff as electricity customer can freely decide whether to adhere to it or not. Still, a neutral score was given due to the fact that if consumers will exceed the tariff, it will be reflected in the costs for them (and revenue for DSO).

Within the criterion of cost, the positive scores were given to the tariff-based and variable connection size solutions. This is due to the fact that these operate in a similar way as the current system. In the best scenario tariffs would be designed such that the revenue of DSO is kept at sufficient levels. The market-based solutions were given neutral score – it is impossible to predict the exact cost for those as a specific market design needs to be considered, including the supply of flexibility, and degree of competition in this market. Rules-based approaches were also given a neutral score – the final cost depends on the degree of reimbursement for use of solutions from this family.

When it comes to social acceptance tariffs and markets scored highest. This is mostly due to the fact that customers right now are accustomed to the tariff systems and switching to the different one would likely not cause that much protest. And in case of market participation would be voluntary. Variable connection size might prove problematic due to the fact that it is a compulsory measure, leaving not that much of freedom of choice. This situation is even more pronounced with the rules-based solution as they are likely to leave even less freedom.

From the point of technical feasibility, the tariff-based solution presents the easiest integration option, as it requires only measurements of electricity consumption with sufficient frequency. This functionality is already offered by the smart meters on the market. Introduction of a flexibility market would require the significant deployment of ICT, smart devices and market development and as such resulted in a lower score. The rules-based solution would require investment from the customer side into the technologies that would limit their consumption and possibly from DSO for the purpose of direct load control. Finally, the variable connection size for households would require simply limiting possible power draw by fuse size or an advanced system that would be able to limit power drawn by customers. However, in the former case, this would likely affect the user comfort and require DSO action each time the fuse get 'tripped' (because the customer should not have access to it) and in latter, it would require use of an additional, possibly complicated, device.

In the field of legal viability, all the proposed solutions would require changes to the regulatory framework. It can be argued that the implementation of power-based tariffs would require the least amount of changes as it simply introduces a change to an already existing system of tariffs. In case of flexibility market legislation that would regulate the market and relations between the parties that take part in it. Similarly, variable connection size and rules-based methods would require a change to legislation defining their extent, remuneration and application.

In conclusion to this chapter, power-based tariffs appear to be the best approach in the short-term, to the activation of flexibility in the households for DSOs purposes. While it is not the best solution in criteria of sufficiency and reliability, it appears to be more viable in the areas of technical and legal viability than the other methods, should be met with potentially higher acceptance and with properly designed tariff it should be more cost-reflective for the usage of the grid. When it comes to a longer-term perspective it can be argued that the criteria of technical and legal viability can be given less weight. In this case, market-based and variable connection size methods would become more interesting. Rules-based methods, while not preferred, might become necessary in cases like one presented when the concept of curtailment was introduced.

Nevertheless, it needs to be noted that those different approaches are not necessarily mutually exclusive. If a tariff-based system would be in place, it can be imagined that a flexibility market might function beside it to provide additional, explicit, flexibility. Furthermore, different activation methods might be utilized for different customer/producer types in order to obtain the best results. Still, within the scope of this project, the tariff-based approach appears to be the optimal method to activate flexibility from the households for the purposes of the DSO. Due to this reason in the modelling part the focus will be put on this method, with the possibility of application of different methods parallel to it.

4. Flexibility modelling

4.1. Introduction

During the research related to flexibility modelling, it quickly became evident that most common approaches, generally related to optimization by minimization of the objective function, might not be applicable based on the requirements presented in this thesis. To give some perspective – most of the current research often looks into a system-wide perspective, more important from the TSO perspective [25], [58]. This perspective is mostly related to the aggregated values for the transmission network for the purposes of its congestion management and generation-demand balancing. While necessary for the correct operation of electrical networks they do not look into the implications for the DSOs. Other studies like ECN and Liander one [56] or J. Reinders thesis [59] approach the topic of flexibility for the DSO use, however the way it is modelled does not present the required granularity and takes certain assumptions, like not taking into account how flexibility provided during one moment in time affects its availability in other moments.

Furthermore, a separate category of studies can be described as ones concerned primarily with optimization problems. Those are mostly focused on EVs and electric heating technologies and have the goal of optimal scheduling from the user or market party (aggregator) cost, rather than from a network asset perspective. Also, their performance might not be acceptable for the purpose of simulation of large areas of MV and LV for multiple years into the future. Furthermore, it is worth mentioning a recent paper on congestion management [60], through Demand Side Management (DSM). It provides enough granularity and performs simulation for 300 days. However, it is done for the day-ahead congestion market working within the day-ahead hourly price market and does not mention how computationally demanding this approach is. Due to that this paper rather presents a solution for a specific situation rather than a way to assess available flexibility in the future.

This need for relatively fast calculations was confirmed during multiple meetings with Enexis' Scenariotool team. For it to be of value and viable for practical use, the maximal time for the simulation couldn't be higher than two to three times longer (2-3 times) compared to the current simulation times within the Scenariotool. To give some perspective simulation done for network consisting of 79 transformers and about 1800 residential loads for five years into the future took about 149 seconds. For a single transformer with 13 residential loads, for one year, the simulation took about half of a second. This produced a strict requirement on the performance side of flexibility modelling and also puts focus on the optimization of developed algorithms.

Furthermore, while DSO is interested in extreme values, it is also interested in realistic ones. Previously, this was represented by the application of simultaneity factors, used to factor out the impossible situations. This further means that common optimization approaches would not be applicable in this situation. This led to the adoption of the current approach of the Scenariotool with Monte Carlo simulation and then getting relevant values (maxima, minima, mean and meaningful percentile values) from the loads generated through stochastic simulation. However, the stochastic approach meant that many more flexibility scheduling/optimization actions would need to take place. Within the current settings, this means the need for 1000 possibilities per simulation of a single household.

Taking all of the abovementioned information into account it became clear that the simulation of flexibility required a special approach. However, for the definition of this approach, the chosen activation method needs to be analysed first.

4.2. Assumed method of activation

As discussed in previous sections one of the most promising approaches for flexibility implementation from the DSO perspective is powerband based approach. While it didn’t provide the best results in all the categories its performance across all of them, reliability and cost reflectiveness were strong arguments for it.

In consultation with the project developed at Enexis Netbeheer, related to the electricity tariffs, a possible implementation of powerband tariff was discussed. Based on it, the most likely model appeared to be the one sharing similarities to the step tariff. Within this tariff scheme, three symmetrical powerbands are available. Consumers are able to choose one of them: low, medium or high. Price of energy varies depending on chosen tariff and whether the energy usage happens inside or outside the band. This can be seen in Figure 4.1.

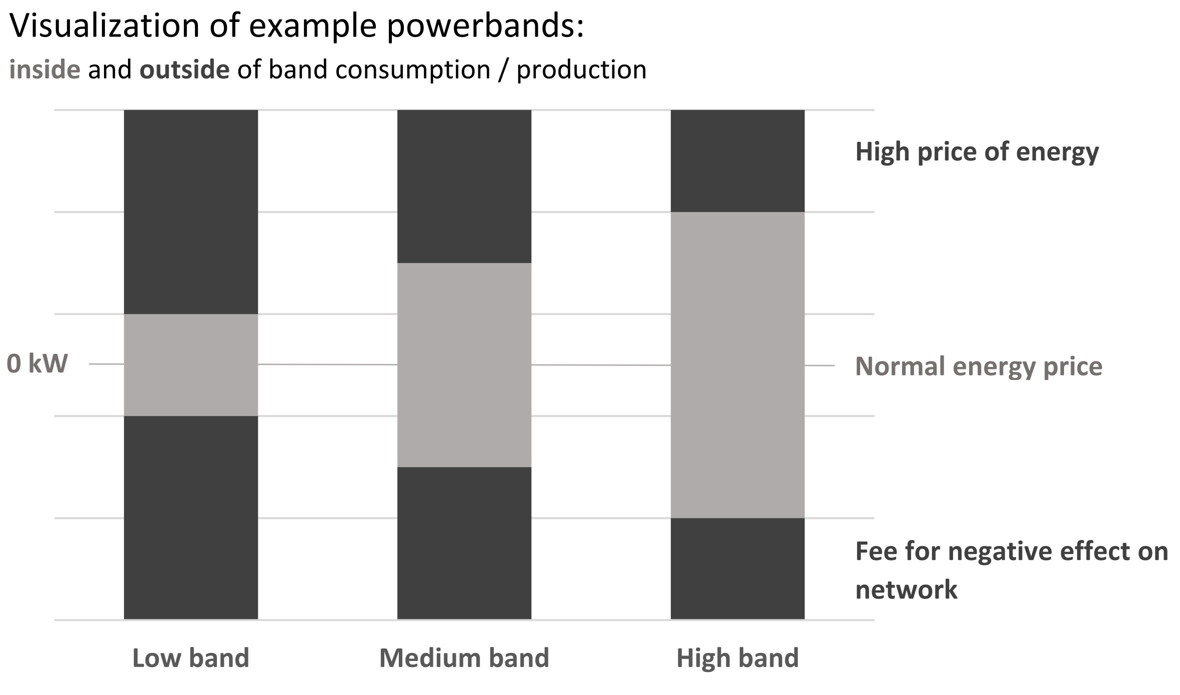

Figure 4.1 Visualization of powerbands for power-bandwidth tariff

For consumption and production within the bands, standard energy prices and rates are applied. However, above the set threshold (e.g. 5, 10, 15 kW for different tariffs), the cost of energy is higher.

However, for the production of electrical energy outside the band, a fee is applied to the responsible producer. This fee presents a higher cost than benefit from energy production for the producer. This approach was taken in order to discourage the introduction of energy above the limit and represent the cost of asset overloading.

For this application, the average power consumption reported with a 15-minute frequency is used. This is done to limit the amount of data that requires logging and provide certain freedom in case of loads that are only activated for short periods of time, but during this time their energy consumption is relatively high (e.g. freezer, dishwasher, washing machine, kettle, hairdryer). This approach better represents the case of the DSO with a focus on the asset overloading. As mentioned in [26] short overloading of assets is permissible as it does not produce enough thermal energy to have an effect on the lifespan of the device.

4.3. Approach

4.3.1. Introduction

In order to better explain how the model operates it was decided to first present it in more descriptive terms in this subchapter and then provide the exact mathematical information that governs the work of the model in subchapters 4.3.2 and 4.3.3. Furthermore, subchapter 4.3.4 related to computational speed optimization was added.

For the purpose of limiting energy consumption, according to the consumption threshold, the model takes the following steps:

1) It calculates a total load (without EV charging, with generation as negative load) of the household,
2) Based on this total load it calculates the available (free) capacity for EV charging for each quarter with restrictions of maximal charging power and keeping positive values,
3) It converts these values to the cumulative capacity, starting at the arrival quarter of the EV,
4) It constructs an EV charging profile based on the values from the previous two steps:
    a. For quarters with a cumulative capacity lower than the energy that needs to be charged, it takes corresponding non-cumulative capacities,
    b. It fills the last quarter of the charging session with remaining energy to be charged, within imposed constraints,
    c. It fills remaining quarters with zeros.

This is visualized in Figure 4.2, as operations on load profiles, and in Figure 4.3, in the form of a flowchart.

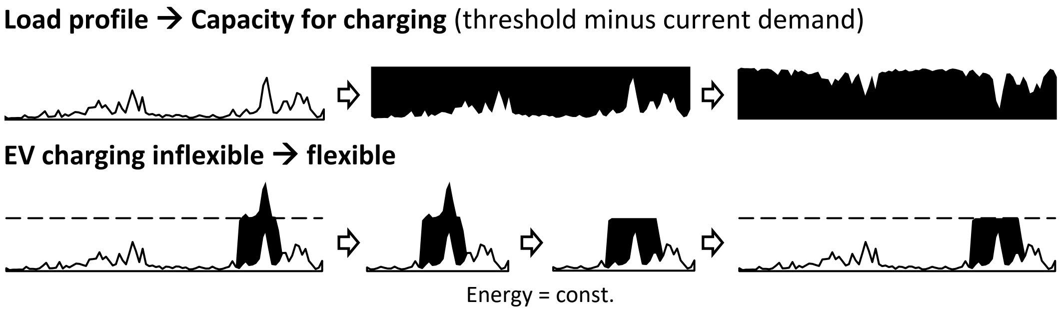

Figure 4.2 Visualization of operations on load profiles for energy consumption

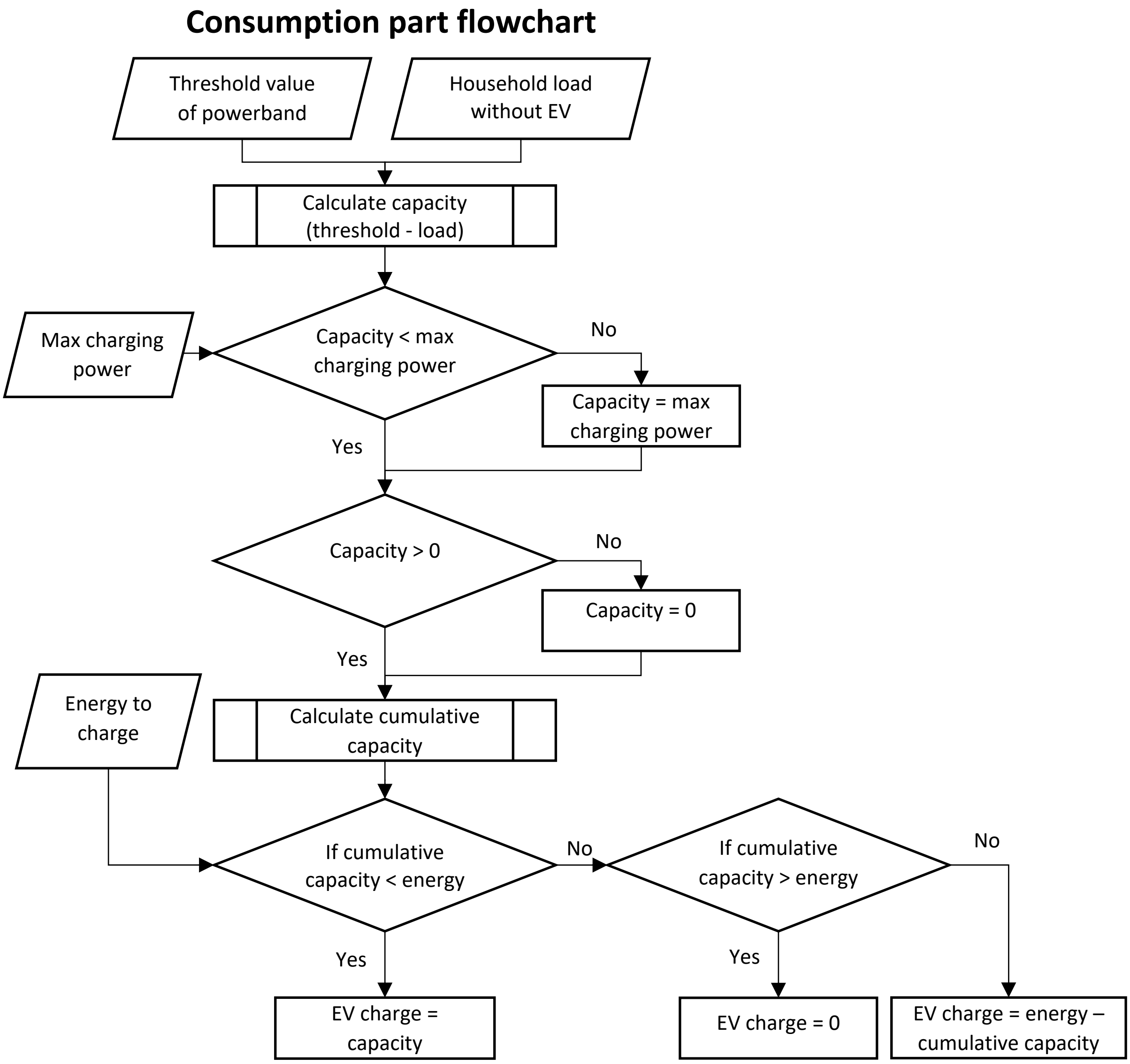

Figure 4.3 Flowchart of the model for energy consumption

For the purpose of limiting energy production, according to the production threshold, the model takes the following steps:

1) It calculates a total load (without generation) for each quarter,
2) Based on the total load it assesses what is maximal possible production for each quarter in order to stay within the threshold,
3) For the quarters where production from PVs exceeds this maximal possible production, it takes maximal production values. For other quarters it takes values of PV production “from before”.

This is visualized in Figure 4.4, as operations on load profiles, and in Figure 4.5, in the form of a flowchart.

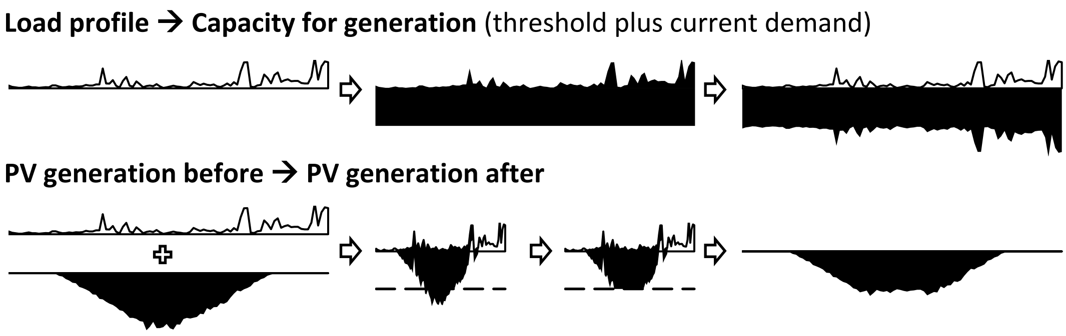

Figure 4.4 Visualization of operations on load profiles for energy production

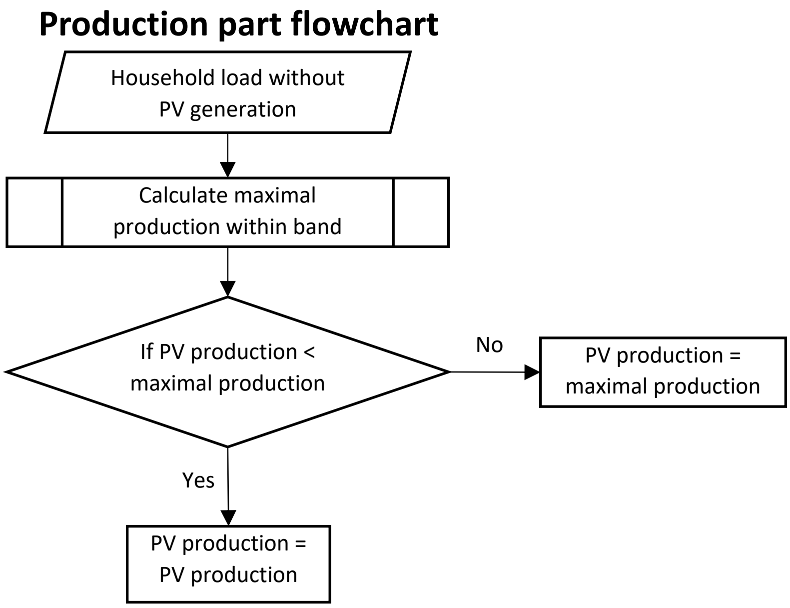

Figure 4.5 Flowchart of the model for energy production

4.3.2. EV charging

For the purpose of EV charging the approach of available capacity for charging was taken. It can be described in the following way.

First, the household load profile without EV charging and, as in Figure 4.3 need to be calculated. The summation of baseload profiles for a given household P_{HH} with load profiles of new technologies (for households that have those) happens. Simultaneously, based on the information about travelled distance $Dist$ from the trip data and taken driving efficiency $\eta_{driving}$, the energy required to charge E_{tot} is also calculated.

$$P_{sum}^{t} = P_{HH}^{t} + P_{HP}^{t} - P_{PV}^{t}, \qquad t \in \langle 0{,}95 \rangle, t \in \mathbb{Z} \tag{1}$$

$$E_{charge} = \frac{d_{trip}}{\eta_{driving}} \tag{2}$$

The combined Profiles for those households that use EV are then shifted based on EV arrival times so that arrival quarters are on first positions of an array. This approach allows to operate on existing and new arrays in a much easier and computationally efficient way – there is no longer need to consider arrival time until the point where those are shifted back to real positions. This shift is dependent on

Python's Numpy package indexing approach. Indices corresponding to the quarters of an hour during a day, t, are then modified based on the arrival quarter.

$$t_{shifted} = t - 96 + qArr \tag{3}$$

This array of shifted indices consists of negative values approaching zero value, which corresponds to the arrival time. With that, a new shifted profile is generated by applying the new order of indices to the normal profile (where negative indices correspond to the values counted from the end of an array).

$$P_{shifted}^{t} = P_{sum}^{t_{shifted}} \tag{4}$$

Then the charging capacity CC is calculated, as shown in Figure 4.3, by subtracting the summed profile from the value of the powerband P_{band}. This charging capacity cannot be lower than zero and cannot exceed the maximal power of EV charger CC_{max}. If it does so it is limited to the corresponding values. This calculation is done for each quarter of an hour for a day of simulations.

$$CC^t = P_{band} - P_{shifted}^{t} \tag{5}$$

$$CC^t = \begin{cases} CC^t, & CC^t \geq 0 \\ 0, & CC^t < 0 \end{cases} \tag{6}$$

$$CC^t = \begin{cases} CC_{max}, & CC^t > CC_{max} \\ CC^t, & 0 \leq CC^t \leq CC_{max} \\ 0, & CC^t < 0 \end{cases} \tag{7}$$

With this, the part related to cumulative capacity in Figure 4.3 is reached. The obtained capacity profiles are used as summands for a partial sum that can be described as cumulative charging capacity CCC – how much energy it is possible to charge within the number of given quarters.

$$CCC^T = \sum_{t=0}^{T} \frac{CC^t}{4}, \qquad T \in \langle 0,95 \rangle, T \in \mathbb{Z} \tag{8}$$

Afterwards, the last two levels of flowchart from Figure 4.3 are executed. The partial sum is compared with the required charge E_{tot} and the values for which it is smaller than the required charge create a new profile with flexible charging $P_{EV,flex}$.

$$CCM^T = \begin{cases} 1, & CCC^T < E_{tot} \\ 0, & CCC^T \geq E_{tot} \end{cases} \tag{9}$$

$$P_{EV,flex}^{T} = CC^T \cdot CCM^T \tag{10}$$

The last quarter of $P_{EV,flex}$ is then filled with a reminder of energy with the requirement that is not bigger than the available capacity for this quarter.

$$T_{last} = \sum_{n=0}^{95} CCM^T \tag{11}$$

$$P_{EV,flex}^{T_{last}} = \begin{cases} E_{tot} - \sum_{t=0}^{T_{last}-1} P_{EV,flex}^{t}, & E_{tot} - \sum_{t=0}^{T_{last}-1} P_{EV,flex}^{t} \leq CC^{T_{last}} \\ CC^{T_{last}}, & E_{tot} - \sum_{t=0}^{T_{last}-1} P_{EV,flex}^{t} > CC^{T_{last}} \end{cases} \tag{12}$$

Finally, those profiles are shifted back so that the arrival time is back in the corresponding place in the array.

$$t_{shifted\ back} = t - qArr \tag{13}$$

$$P^{t}_{EV,new} = P^{t_{shifted\ back}}_{EV,flex} \tag{14}$$

In this way, the flexible charging profiles for the sensitive subset of drivers are obtained. For the insensitive subset, inflexible profiles are used. Generation of those is explained in Appendix IV: Fast EV profile generation.

It can also be mentioned that if in the current implementation P_{band} was to be provided in the form of an array with specified values for the quarter of an hour within a day it would be able to mimic a variable connection capacity with fixed time element or power-based tariff with band value varying during a day.

4.3.3. PV curtailment

PV curtailment is done in a somewhat similar way to the EV flexible charging. First, the baseload for the PV is created by adding the household load P_{HH}, HP load P_{HP} where applicable and new EV load $P_{EV,flex}$ (which can be flexible or inflexible depending on the sensitivity setting). Then PV generation P_{PV} is added.

$$P^{t}_{sum} = P^{t}_{HH} + P^{t}_{HP} + P^{t}_{EV,flex} - P^{t}_{PV}, \qquad t \in \langle 0,95 \rangle, t \in \mathbb{Z} \tag{15}$$

Then it is checked during which quarters the production is outside of the bandwidth. And according to the mask, PV output is reduced to not exceed the bandwidth.

$$PV^{t}_{mask} = \begin{cases} 1, & P^{t}_{sum} < -P_{band} \\ 0, & P^{t}_{sum} \geq -P_{band} \end{cases} \tag{16}$$

$$P^{t}_{PV,curt} = P^{t}_{PV,uncurt} - \left(PV^{t}_{mask} \cdot (P^{t}_{sum} + P_{band}) \right) \tag{17}$$

The amount of curtailed energy can then be examined with optionally generated data – this can be used to estimate costs related to the curtailment. However, it needs to be considered that the simulation is run for two example days during a year – a representative summer and winter one. The PV panels are more likely to exceed the powerband in Summer and this day is likely to represent higher than usual irradiance scenario.

4.3.4. Performance optimization

It needs to be mentioned that after initial attempts at the development of scheduling scripts, it became apparent that from the performance side (speed of computations), simulation for the asset for given year and season (summer or winter) would be preferably done in one run. This necessitated work on relatively big matrices for given load profiles that contained data for all households and iterations per type of load. With assumptions of 1000 iterations and 96 time periods per day of simulation (15-minute frequency), this means that for a neighbourhood with e.g. 80 houses, 30 PV panels, 25 EVs and 20 HPs, the script needs to operate on matrices of 80 000x96, 30 000x96, 25 000x96 and 20 000x96. Any attempts to work iteratively on the data would negatively affect performance. Due to that, all the operations were done simultaneously without any usage of loop statements. As the biggest number of households that was found to be connected to the single asset in Enexis' data was about 1400, it can give an idea regarding the size of certain matrices (1 400 000x96).

However, this introduced certain difficulties when it came to random assignment of new technologies to the households while preserving an equal number of those between the iterations and not affecting computation speed. This difficulty was resolved by generating arranged arrays up to a number of houses per each iteration, shuffling their contents iteration-wise and creating a boolean mask from a comparison of numbers within the array to the number of units of a given technology.

4.4. Assumptions and variables

Due to the requirements of the project the model needs to evaluate multiple LV networks within one request from the user of the tool. This introduced the requirement of computational efficiency for implementation. Furthermore, due to the limits in the geographical resolution of the available data, it was required to operate on the averaged values, most commonly per zipcode. Because of this, certain assumptions need to be taken.

The main load that is optimized are the EVs
While exploring the impact of new technologies on household peak energy consumption, EV charging was identified as having the biggest impact. This examination was done with the assumption of using a 3.6 kW charger. In the case of ‘faster’ chargers, the impact would be even higher. Furthermore, available data allowed for better insight into driving behaviour. All of these reasons resulted in a focus on EV charging optimization.

Heat pumps, electric boilers and electric cooking are not subject to optimization
Electric thermal loads are considered inflexible for the purpose of this thesis. This was done due to the following reasons. Firstly, a different approach would require a closer correlation with outside temperatures during the winter period with a certain degree of spatial difference (due to the size of the area examined). Secondly, the maximal power consumption decrease for a 200-litre electric water heater was found to be of about 0.3 kW in [25]. While it can be sustained for about 10 hours it is still quite small and requires a relatively big boiler. Thirdly, for heat pumps, according to [38] the reduction in loading would be of about 0.16 kW. For electric cooking, specific numbers were not found. This all means that the implementation of electric heat devices would negatively affect the performance while not providing that much accuracy or meaningful results.

For PV generation approach of curtailment is be applied
As mentioned before, for PV panels the approach of curtailment is applied. As presented before this approach represents the effects of power-based tariff the best. In order to analyse the effect of curtailment on energy production, values for inside and outside the band production from before and after curtailment should be available for later examination. The exact reaction of PV owners would need to be examined in pilot projects, however in the case when their response is not that uniform, it would be possible in future to apply sensitivity values to their behaviour.

White goods (dishwasher, washing machine, dryer etc.) will be assumed to be part of baseload
While white goods present an interesting opportunity when it comes to the provision of flexibility, proper assessment of the available flexibility might not bring enough information and accuracy to be valuable for the model at this point. According to the research over previous pilots that tried to activate flexibility from those devices [38], available reduction in loading would be only between 20 and 65 watts per household. Moreover, it would need to be considered at specific points in time and in relation to the previous activations. Furthermore, available datasets of household loads consisted of aggregated loads at point of connection to the DSO network. In order to accurately assess flexibility availability, load disaggregation would need to be applied for the profiles with a 15-minute resolution, which would negatively affect the performance of the model.

EV owner behaviour is simplified to a percentage of tariff sensitive owners.
During the development of the model, it was decided that it is better to simulate the outcome of EV owners' behaviour instead of their behaviour. This is due to the reasoning that the simulation of drivers behaviour would likely introduce more inaccuracies into the model. This is also related to the fact that final tariff parameters, as e.g. energy cost inside and outside the band, were not defined at this stage and tariff design is outside of the scope of this work. Moreover, according to [61] the charging behaviour between EV owners presents a high degree of individual heterogeneity. Rather than try to model behaviour, it was decided to examine its outcomes, e.g. what if 60% of owners were sensitive to the tariff. Sensitive owners would always keep their EV related consumption under the band, while insensitive would exceed it freely. This was supported by that human longer-term commuting behaviour shows a certain degree of habituality. In this thinking, sensitive households would stick to their behaviour – with small deviations related to "unusual" events that would require them to become insensitive. Such sensitivity values would then be possible to examine during possible pilot projects.

EV owners charge only at home
For the purpose of EV charging it was assumed that EV owners will charge only at their homes. Based on the scope of the thesis and current approach taken in related research such approach should provide enough accuracy. Furthermore, with growing numbers of EVs, it can be assumed that not everyone will have the possibility of charging at work, mall etc. Then charging would happen mostly at homes. For those reasons, it was decided to assume the scenario where everyone tries to charge at their own home, as it also can result in higher demand from the households. Furthermore, this approach was also in line with assumptions done for the Scenariotool where it is also assumed that EV owners charge entirely at homes.

EV owners try to charge the amount of energy equivalent to their daily energy usage
Based on the data obtained from the OViN research [13] trip data for Dutch car owners was obtained. This data was then used to generate hypothetical EV trips consisting of departure time (in 15-minute resolution), arrival back at home time and distance travelled. This data, together with assumed EV charger speed and seasonal driving efficiency (km/kWh) was transformed into charging data and inflexible profiles.

Variable speed EV chargers are available to the sensitive subset of EV owners
It is assumed that variable speed EV chargers are available to owners of EVs and they are able to use them. Such technology is already available and should be more widespread in the future. It was assumed that the efficiency of the charger will be included in the seasonal driving efficiency. It was assumed that this efficiency will stay constant for different charging speeds of the same charger. Lastly, it was assumed that such a charger is able to regulate its output power with high granularity.

The charger has insight into the current power at the connection to the grid
For the approach of the power step tariff, it was assumed that the EV charger would have insight into the current power draw/push at the point of connection of household with the grid. In this sense, it could have access to the measured power input and output from the smart meter responsible for logging energy consumption. This is required for the EV charger to apply variable charging speed in accordance with the powerband.

All EV owners have access to similar speed EV chargers
As the prediction of the exact size of the EV charger at the household level it was not possible due to the access to data with required resolution, it was decided to use uniform number. The reasoning behind this approach is that while it might produce some inaccuracies with a small number of EVs, with bigger numbers the average starts to represent reality more closely. This means that in cases where

EVs start to have a bigger impact on the component loading (with their growing number) the inaccuracy decreases. Furthermore, it is assumed that EV owners will likely switch from the 1-phase connection to 3-phase one should they want higher charging speeds. The limit will be imposed as to not violate the 3-phase connection size (3x25 A) at the household point of connection with the grid. This limit can be changed to the single phase one, should it be required (5.7 kW).

Simulation is done with a quarter of an hour frequency.
In order to preserve consistency with the input values, load profiles generated for the Monte Carlo method and previous assumptions simulation will be done with 15-minute resolution. For the purpose of peak shaving, in order to prevent overloading of the equipment, such granularity is sufficient. Furthermore, the higher frequency would have a negative impact on the computational performance of the model, which would be against project requirements.

For the current implementation, it is assumed that there will be maximally 1 EV per house
This assumption was put in place based on thinking that for the most of households the likelihood of getting more than one EV with current price and adoption ratios is not that likely. Furthermore, an attempt at removing this limit would require multiple new assumptions, introducing more uncertainty into the model.

The distribution of new technologies between the households connected to the simulated asset will be random between the Monte Carlo simulations
As the adoption data for the new technologies was based on the aggregates per network asset it is impossible to determine the exact distribution of these between the households. Furthermore, the correlation between ownership of different technologies was also not available, for the same reason. For these reasons it was decided that per each iteration of Monte Carlo draw, load profiles of new technologies will be assigned to the random households. Within the used number of iterations, this approach should cover most of the possibilities of technology distribution. Furthermore, as the penetration of new technologies approaches 100%, which corresponds to the less desirable scenarios with higher loads, this method should become more accurate.

EV charging session can be unfinished
It was decided to not implement any checks against unfinished charging sessions. This was done for few reasons. Firstly, even at assumed low charging speed setting (3.6 kW) and powerband setting of 4 kW cause only an increase of 1.6 percentage points over the percentage of unfinished sessions without flexibility. For chargers capable of utilizing more power this would only decrease. Secondly, this happens mostly for trips with long distances and it can be argued that these are unlikely to be repeated very often. Thirdly, it was considered to introduce "charging anxiety" setting, in which if it would not be possible to charge the load within the flexible session it would use inflexible profile. However, it was decided that cases like that would be better represented by insensitive behaviour, especially since it happened only in a low percentage of cases.

PV panels have a uniform output for simulated LV network
Based on the available data it was assumed that the output of PV installation in the neighbourhood is the same for each installation. This is mostly due to the fact that information used for differentiation of PV panel size is yearly energy consumption of the household and implementation within Scenariotool required aggregate value. Due to that PV panels were sized to the same size and their profiles within a single iteration of Monte Carlo draw are the same. In real life, there might be some more variation: different houses having different sizes of the PV installations, with different orientations of the panels and a possibility of shading effect. However, as data on this is not readily available, trying to predict those might prove more inaccurate than the current method.

Moreover, variables of the model, represented by inputs and outputs, can be seen in Appendix I: Inputs and outputs.

4.5. Results

4.5.1. Introduction

In order to present the results of the algorithm in an understandable way, it was decided to do it by certain steps of aggregation. Firstly, results will be presented for specific technologies, in relation to household profiles. Starting from the household with one EV and one PV panel, an analysis will progress to households with multiple technologies (asset level) and finally examine results at the network level. For the household and asset levels, the penetrations of technologies will be predetermined to show the impact of the flexibility. For network results, this data will be based on the technology adoption data from the Enexis' Scenariotool and real asset data (number of households connected, average energy consumption, etc.). Furthermore, examples of the effects of different settings of sensitivity and powerband threshold will be shown. For network simulations, technology adoption values will be based on example scenarios ''GG'' and ''50''. For the adoption values related to these refer to Appendix I: Inputs and outputs.

For single element or household level, over one iteration, only simple graphs depicting load before, after and shifted energy will be presented.

For further aggregation levels, due to the use of the confidence band approach, the following style of graphical representation of results will be used for visualization. The load profile before application of flexibility will be represented by an area filled with the grey colouring. It will represent the range from the 5th to the 95th percentile of possible loading values for a given quarter. The load profile after application of flexibility will be represented by two black lines that will correspond to borders of the area depicting a range from the 5th to the 95th percentile of possible loading values for a given quarter with flexibility. An example of this can be seen in Figure 4.6. In this and next figures E_{avg} corresponds to the average energy consumption of the households connected to the asset.

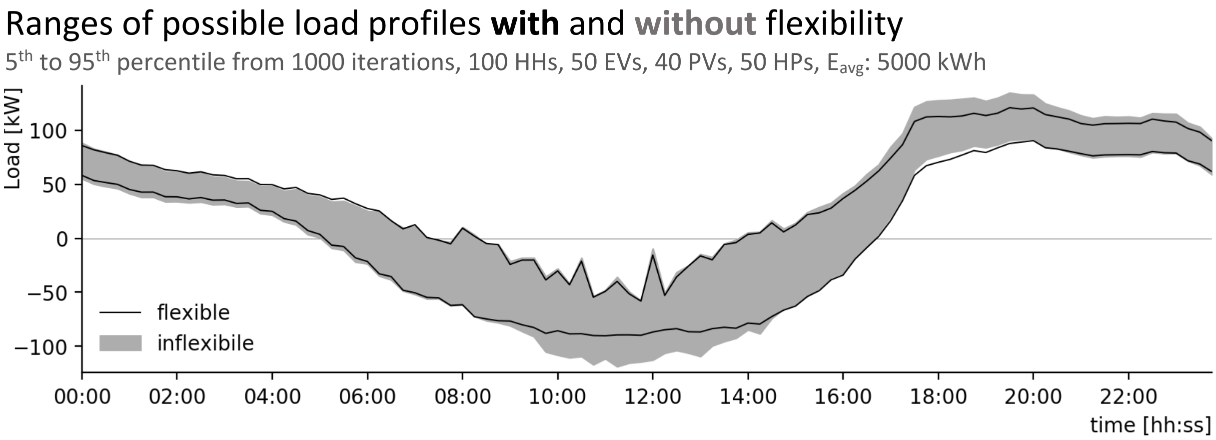

Figure 4.6 Example of result visualization

On the asset level, it was decided that the effects of the powerband tariff will be best shown through visualization of the probability of daily peak loading value across from all the iterations of Monte Carlo simulation. These values will be absolute loading values, not discerning whether power is consumed or produced. The visualization will be performed by means of a histogram for which a probability curve was fitted. This probability curve will be a representation of the probability density function (PDF)[3]. This is a “function of a continuous random variable, whose integral across an interval gives the probability that the value of the variable lies within the same interval” [63]. The example of such a graph can be seen in Figure 4.7.

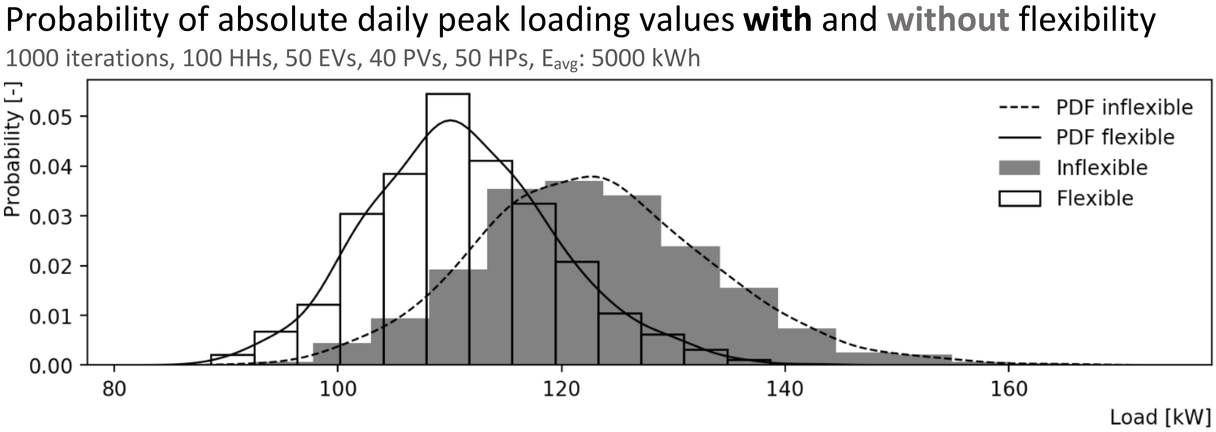

Figure 4.7 Example of peak loading probability from 1000 iterations of Monte Carlo simulation

Furthermore, since different settings for powerband and sensitivity will be used, images might have additional description in following convention: (powerband) lim(it): Y (kW), sens(itivity): Z (%), seas(on): wi(nter)/su(mmer). So, example result for powerband of 5 kW and 70% of EV owners being flexible, during the summer will be presented as “lim: 5, sens: 70, seas: su”. Parts of this description that are not relevant for given simulation will not be put in the descriptions.

4.5.2. Household level

To represent how the algorithm works for EVs, in a most understandable manner, it is better to show the result already at the household level. The EV load alone could be shown; however, since it is specifically optimized to limit consumption outside the band (which is the sum of all the consumption and production at the household connection with the grid), such representation wouldn’t show its effect in a clear way. Instead, the tariff’s effect on EV can be seen in Figure 4.8, which shows load profiles of household (baseload) and of EV together with household, before application of tariff (inflexible) and after (flexible). Moreover, in this graph, the shifted load is emphasised.

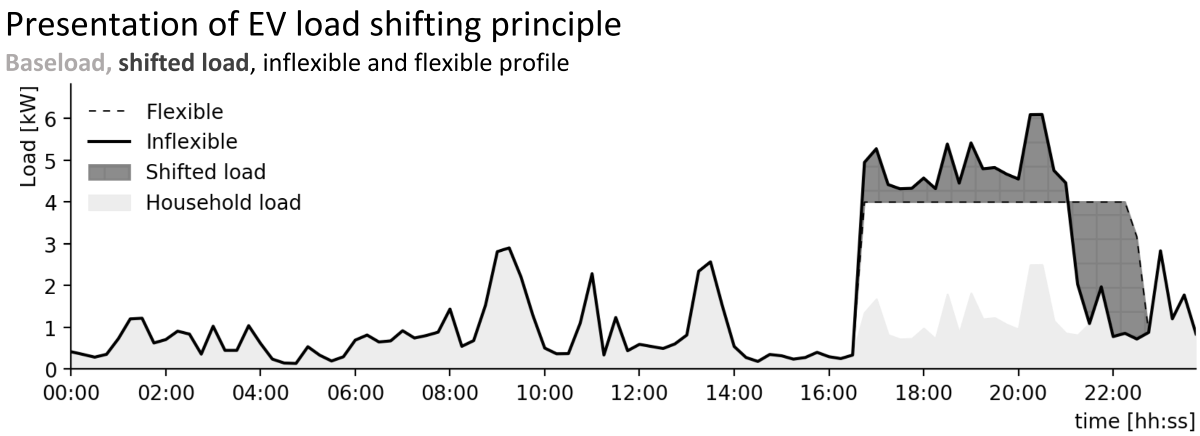

Figure 4.8 Presentation of EV load shifting principle (lim: 4.0, sens: 1.0, seas: wi)

[3] PDF will be obtained by approximation through kernel density estimation (KDE): “a non-parametric way to estimate the probability density function of a random variable” [62].

To further present the effect of the tariff, the load profile for 1000 iterations and 10 households (HHs) with 10 EVs is shown in Figure 4.9. In it, the reduction in peak loading corresponds to 4.4 kW (~13.6% reduction compared to peak from inflexible load profile).

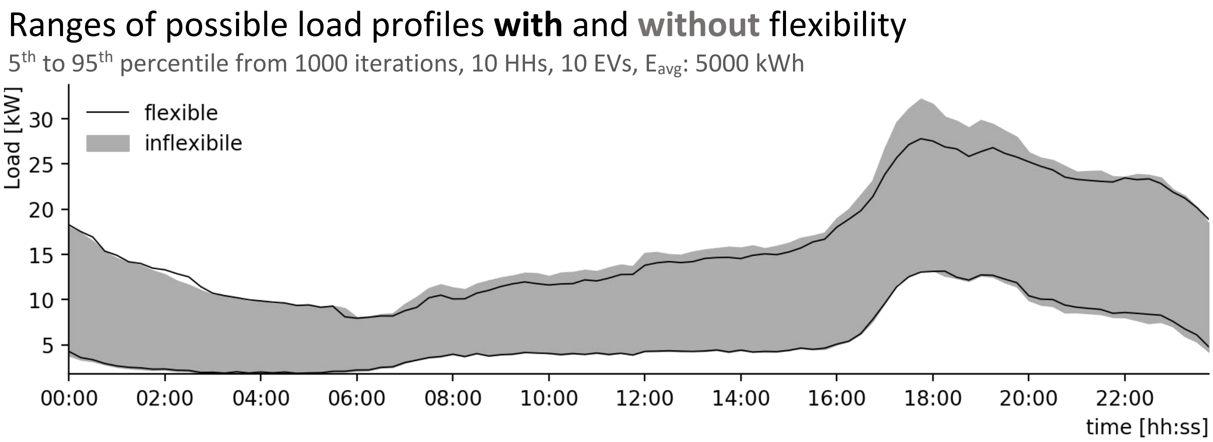

Figure 4.9 Possible range of loads for 10 HHs and 10 EVs across 1000 iterations (lim: 4.0, sens: 1.0, seas: wi)

A similar visualization can be done for the PV panels. The principle is shown in Figure 4.10, which depicts a load profile of household (baseload) together with PV production before application of tariff (inflexible) and after (flexible). In this figure, the curtailed load is also emphasised.

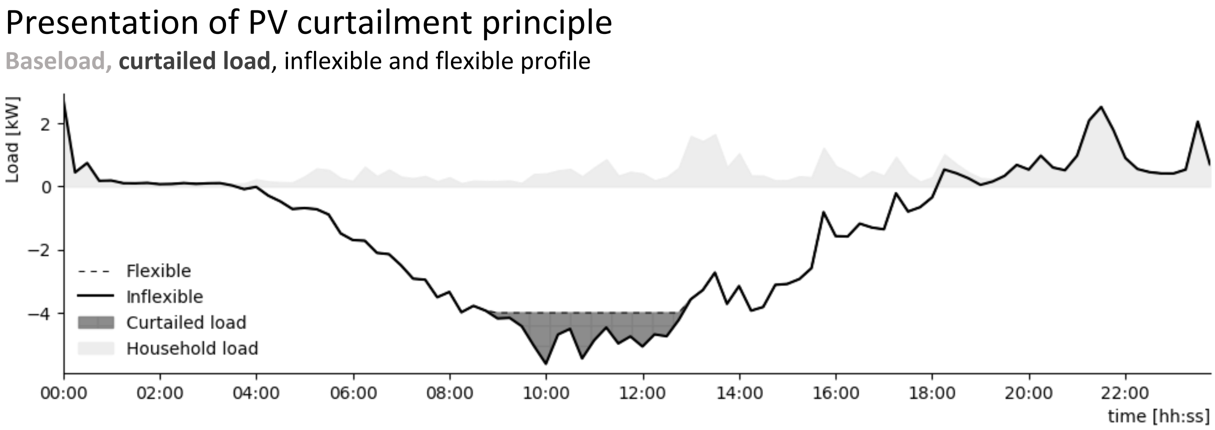

Figure 4.10 Presentation of PV curtailment principle (lim: 4.0, seas: su)

Again, to further present the effect of the tariff, the load profile across 1000 iterations for 10 HHs, out of which 5 have PVs can be shown in Figure 4.11. This time, the reduction in peak loading corresponds to 3.4 kW (~15.5%).

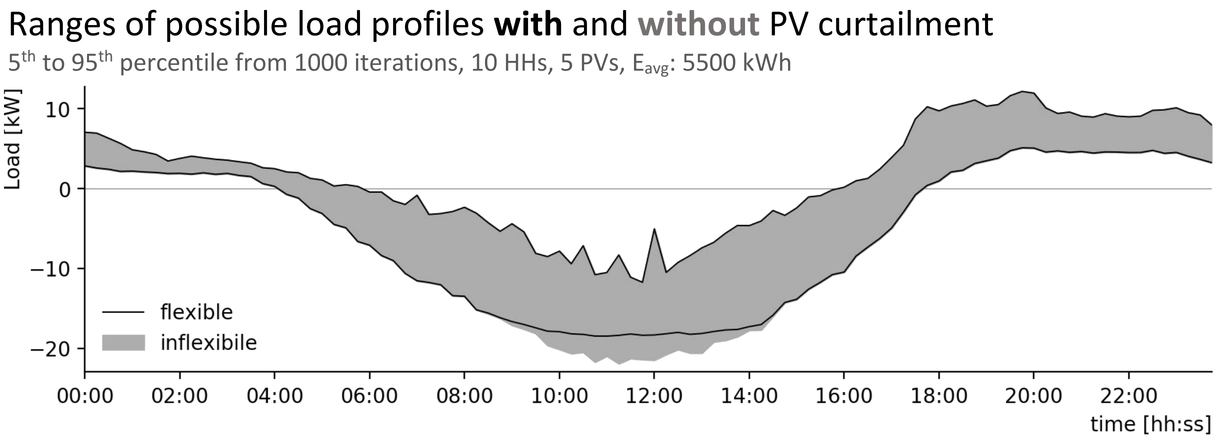

Figure 4.11 Possible range of loads for 10 HHs with 5 PVs across 1000 iterations (lim: 4.0, seas: su)

While these figures show the basic principle behind the algorithm and prove that it works as intended, its effects need to be examined at the higher levels in order to get the whole picture and completely verify its results.

4.5.3. Asset level

For the asset level, some assumptions need to be defined beforehand. The effects of the tariff will be presented for a demand coming from 100 HHs. The effects will be shown for varying levels of penetration for EVs and PVs technologies. In these results HPs will be considered as part of the baseload and their penetration will be fixed at 50% (50 HPs). Simulation for PVs will be done for the Summer period, in order to show their highest impact. Similarly, simulations for EVs will be done for Winter, due to the higher demand from HPs in this season. It needs to be emphasized that graphs in this subchapter will share the same axis values within the same figure.

The impact of EVs on the peak loading with penetrations of 25, 50, 75 and 100%, can be seen in Figure 4.12. Based on it, it can be said that, within the simulation, the power-based tariff decreases the impact of the growing number of EVs onto the asset, as it was planned. While the loading still increases it does it at a much smaller pace than in the situation "before".

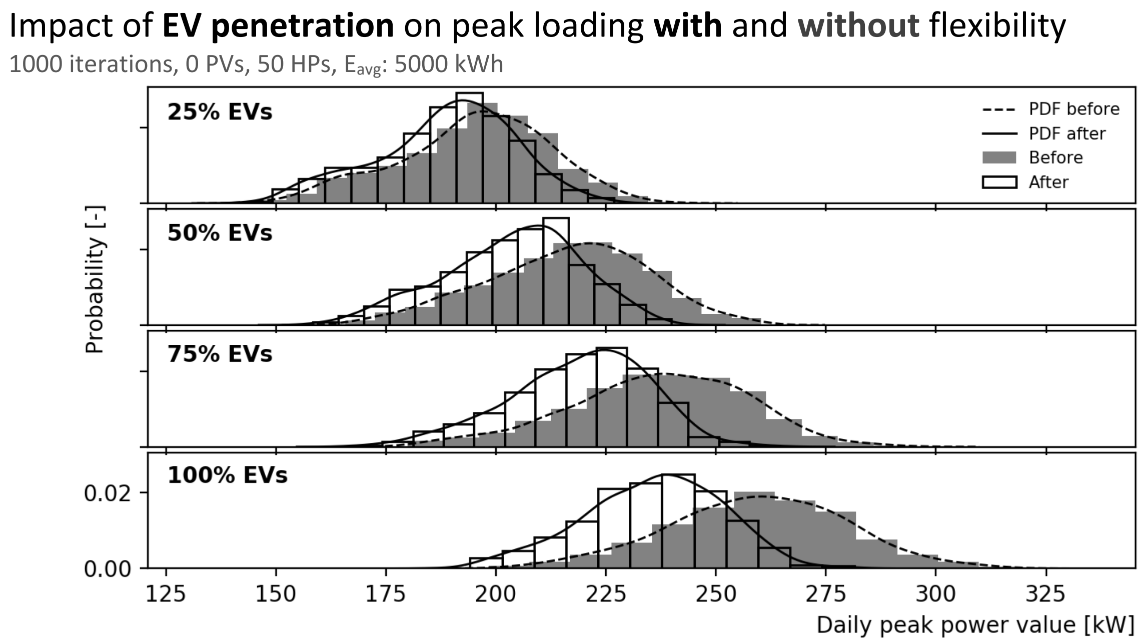

Figure 4.12 Impact of EV penetration on the loading of an asset with 100 HHs, 0 PVs (lim: 4.0, sens: 1.0, seas: wi)

The impact of PVs on the peak loading with penetration of 25, 50, 75 and 100%, can be seen in Figure 4.13. This one also shows that with growing PV penetrations the tariff reduces the impact onto the grid. However, the tariff is not able to slow the growth of the peak loading with increasing penetration – for each penetration step there is still very visible (70-120 kW) increase in loading. This might be attributed to the simultaneity of energy generation from PV panels. In this sense, high penetrations of PVs can still significantly affect the assets.

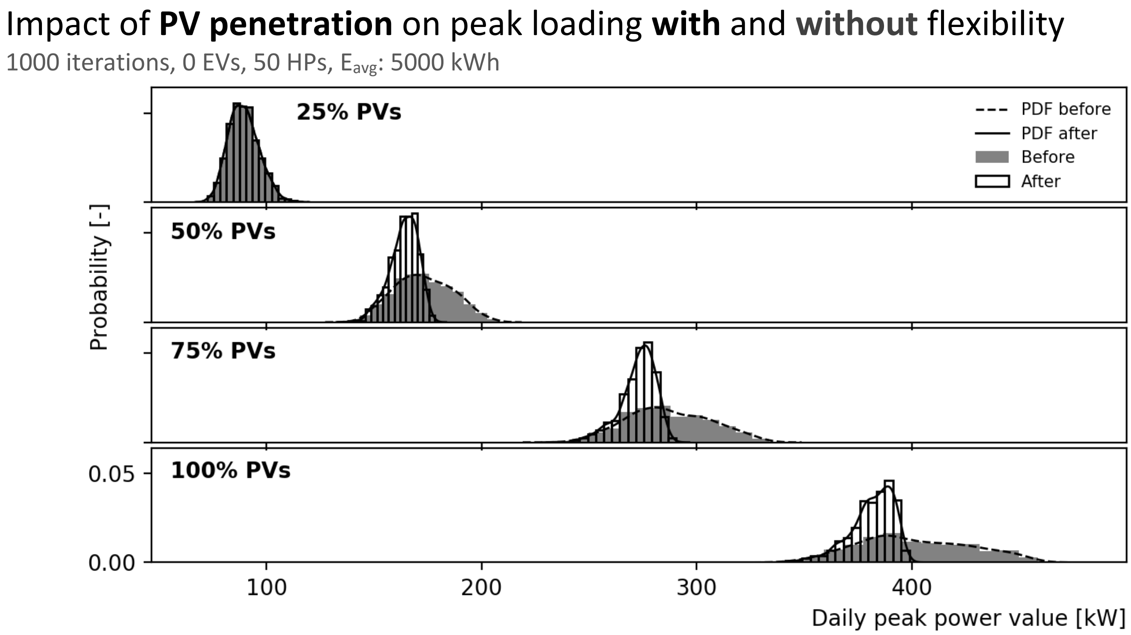

Figure 4.13 Impact of PV penetration on the loading of an asset with 100 HHs, 0 EVs (lim: 4.0, seas: su)

Furthermore, the impact of the power-based tariff limit can be examined for values of 2, 3, 4 and 5 kW with 35 PVs connected. The result of such simulation is shown in Figure 4.14. In it, there is a small difference between the 2 and 3 kW band. Also, it appears that 5 kW band does not affect the loading in this simulation.

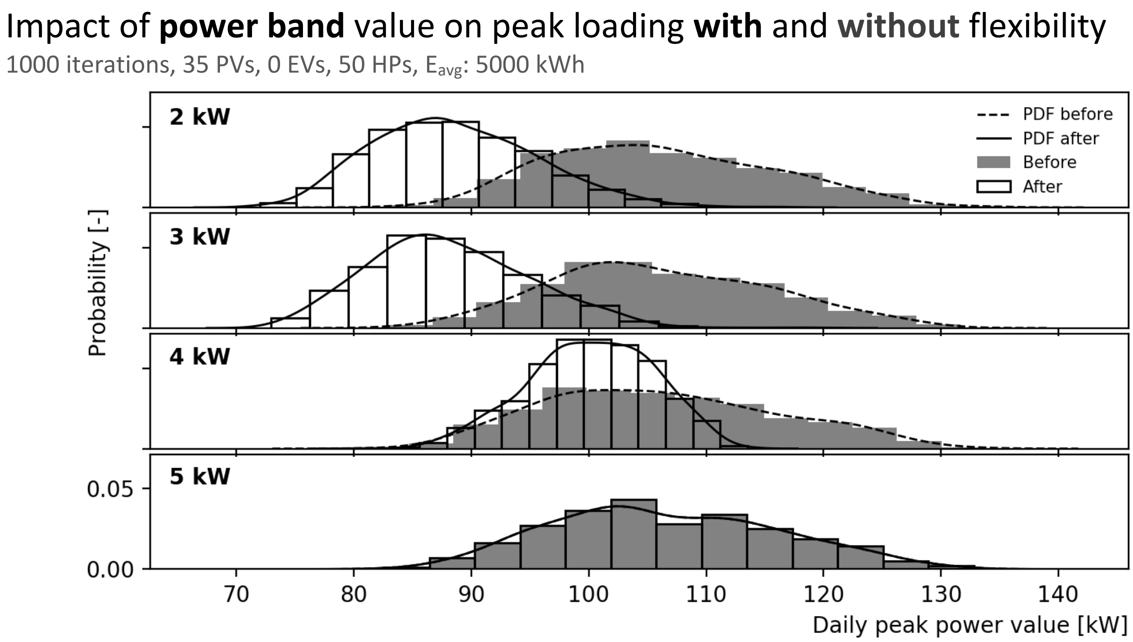

Figure 4.14 Impact of powerband value on the loading of an asset with 80 HHs, 30 PVs, 0 EVs (lim: 4.0, seas: su)

This is caused by the fact that the power pushed into the grid, at the connection point, is lower than 5 kW, the threshold value for the simulation. This can be seen in Figure 4.15. This does not vary with the PV penetration levels but changes with different average energy consumption at the asset level. This is to be expected, due to the fact that in the model the size of the PV installation is scaled to the average yearly energy consumption, it is expected that summer peak loading at the household level is coming from the PV systems. And with higher penetrations of these, the impact on the asset level becomes more visible due to their simultaneous generation.

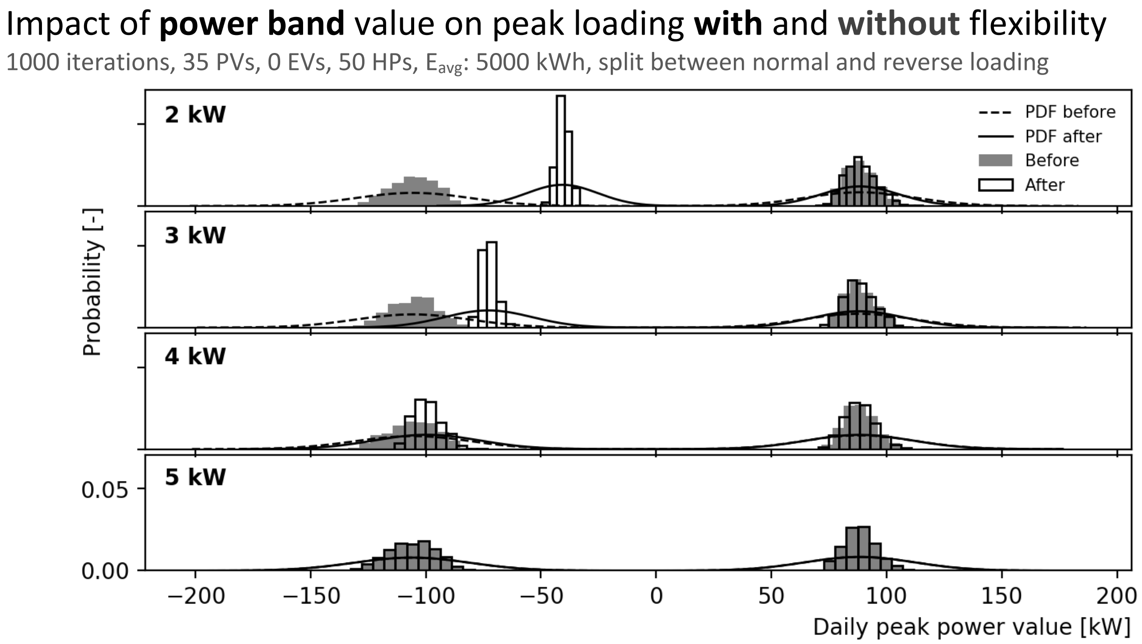

Figure 4.15 Data from Figure 4.14 split between the normal and reverse loading

The impact of power-based tariff band value on EV-based loading can be examined with the same values as for PVs. In this case, simulation is done for 100 HHs with 50 EVs. The results of this can be seen in Figure 4.16. The impact of the tariff can be clearly seen, especially for the steps of 2 and 3 kW. This is to be expected, as it is below the maximum charging power of EV. However, it comes with the disadvantage of a higher number of unfinished charging sessions – while the bands of 4 and 5 kW do not seem to have a significant effect, the lower ones produce a perceivable difference. Further examination of unfinished charging sessions was included in Appendix II: Unfinished charging sessions.

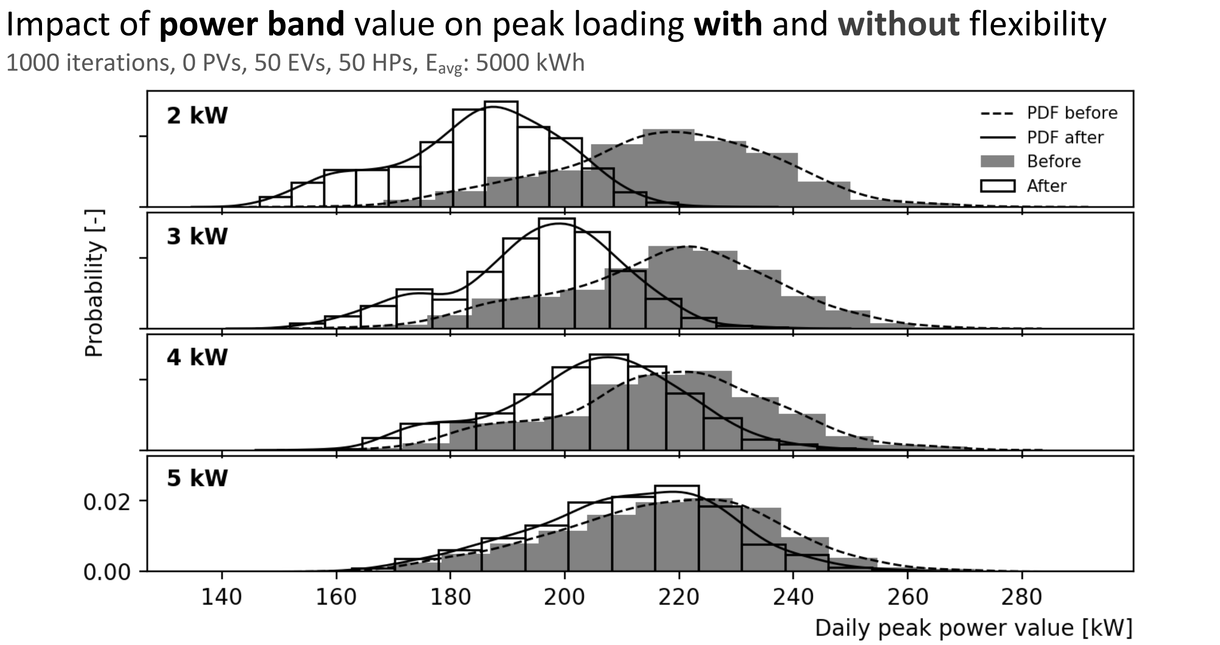

Figure 4.16 Impact of powerband value on the loading of an asset with 80 HHs, 0 PVs, 40 EVs (sens: 1.0, seas: wi)

The impact of the sensitivity setting can be examined with values of 25, 50, 75 and 100%, a band of 4 kW and EV penetration of 50%. Based on Figure 4.17, it can be seen that with a higher number of ‘sensitive’ EV owners the reduction in peak loading becomes more significant. However, based only on this figure it can be hard to directly assess the reduction.

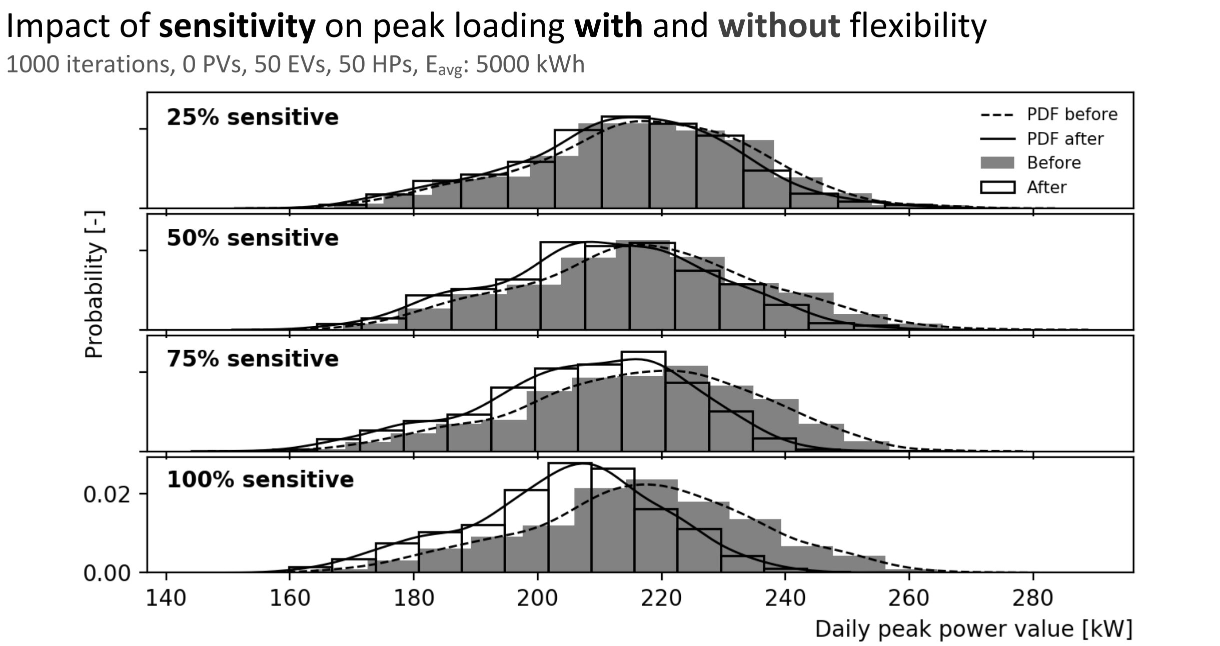

Figure 4.17 Impact of sensitivity value on the loading of an asset with 100 HHs, 0 PVs, 50 EVs (ch: 3.6, lim: 4.0, seas: wi)

For this reason, exact reductions in asset peak loading were further examined. The results for the 95th percentile of values for the range of sensitivity from 10 to 100% with 10% step, both at the asset level and compared only to the pure EV load, can be seen in Table 4.1. Based on these, it can be said that the relation between the sensitivity setting and reduction in peak loading appears to have a linear correlation. The visualization of this correlation can be seen in Figure 4.18.

Table 4.1 Sensitivity analysis of EV owner sensitivity to the tariff, average from 10 simulations

Reduction		Sensitivity									
		10%	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Asset level,	**in kW**	2.31	4.58	7.02	9.29	11.77	14.50	17.34	19.90	21.82	24.48
	in %	0.98	1.93	2.97	3.93	4.97	6.12	7.32	8.39	9.22	10.33
Only EV load,	**in kW**	2.01	3.89	5.60	7.35	9.20	11.03	12.73	14.49	16.23	16.92
	in %	2.73	5.28	7.63	9.98	12.55	15.08	17.29	19.62	22.01	23.02

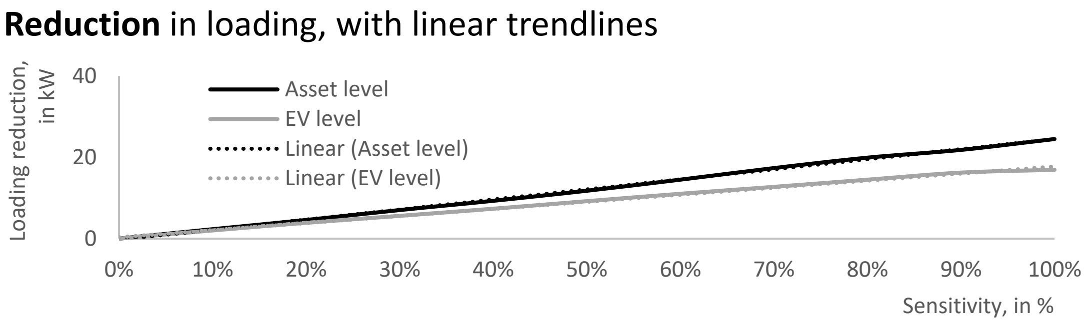

Figure 4.18 Visualization of data from Table 4.1

The impact of the powerband tariff can be clearly seen in the results of this section. One of the more interesting findings in this section was that with curtailment at the household level with higher penetration of PV panels still have a significant impact on the asset loading. This can be attributed to their simultaneity in peak generation.

However, the DSO might be more interested in the analysis at the level of its operation – the network level.

4.5.4. Network level

For the purpose of examining results at the network level, the used metric is the number of assets, further split by the number of years by which investments into new ones can be delayed, when compared to the baseline scenario without flexibility. These values will be expressed in the number of transformers and length of cables, which replacement can be deferred. Furthermore, this number will be grouped by a number of years by which given asset can be operated longer over the base scenario duration (without flexibility). This will be assessed using the limit of 120% loading for transformers and 100% for cables, the same ones as taken in Scenariotool.

For the purpose of asset analysis following networks will be examined: Buggenum (BUGG), Dedemsvaart (DDV), Born (BORN), ‘s-Hertogenbosch Noord (HTN), Tilburg Centrum (TBC) and Tilburg Noord (TBN). Those were chosen because they present an interesting mix between the strongly urban networks (TBC), urban with also smaller cities (HTN, TBN) and with smaller towns with rural areas (BORN, BUGG, DDV). Their locations in the Netherlands can be seen in Figure 4.19.

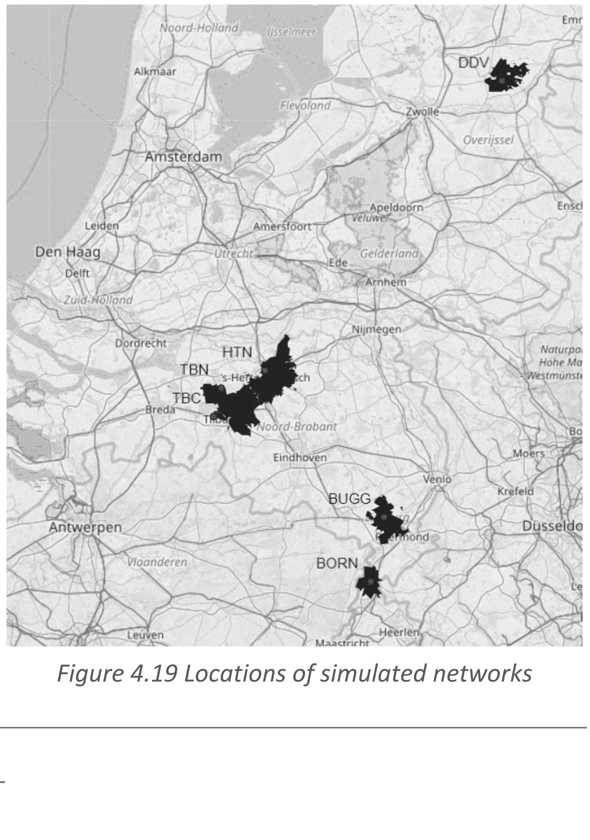

Figure 4.19 Locations of simulated networks

Furthermore, the comparison will be done for the 'GG' (gradual growth) scenario and '50' (rapid growth up to 50% national penetrations of all technologies) scenario. The exact values for per year national penetrations are included in Appendix III: Technology adoption scenarios Simulations within this scenario will be further examined for the powerband values of 3, 4 and 5 kW and sensitivity values of 40, 60 and 80%. All of the scenarios will be examined with PV curtailment. For a better perspective, the number of assets simulated was included in Table 4.2, as well as numbers of assets experiencing overloading in both scenarios.

Table 4.2 Grid assets in simulation: total number and number of ones experiencing overloading

	MV/LV transformers [-]	MV cables [km]	LV cables [km]
Total in simulation	2387 (100%)	~2445.00 (100%)	~2088.00 (100%)
Experience overloading in 'GG' scenario	104 (4.4%)	81.23 (3.3%)	45.17 (2.2%)
Experience overloading in '50' scenario	317 (13.3%)	232.16 (9.5%)	102.46 (4.9%)

The visualized results for the transformers can be seen in Figure 4.20. This visualization is based on the results from Table V-A from Appendix V: Deferral data tables. Based on this figure and data, it can be seen that the number of transformers, for which deferral is possible, is between 17 and 77. This number is higher for bigger percentages of sensitive EV owners and lower powerbands. For the majority of assets experiencing overloading, deferral is possible for only one year – this is valid for on average 78% of transformers for which deferral is possible in the first place. For the assets for which it is possible to defer replacement by 3 or 4 years, the number does not vary that much within the single powerband.

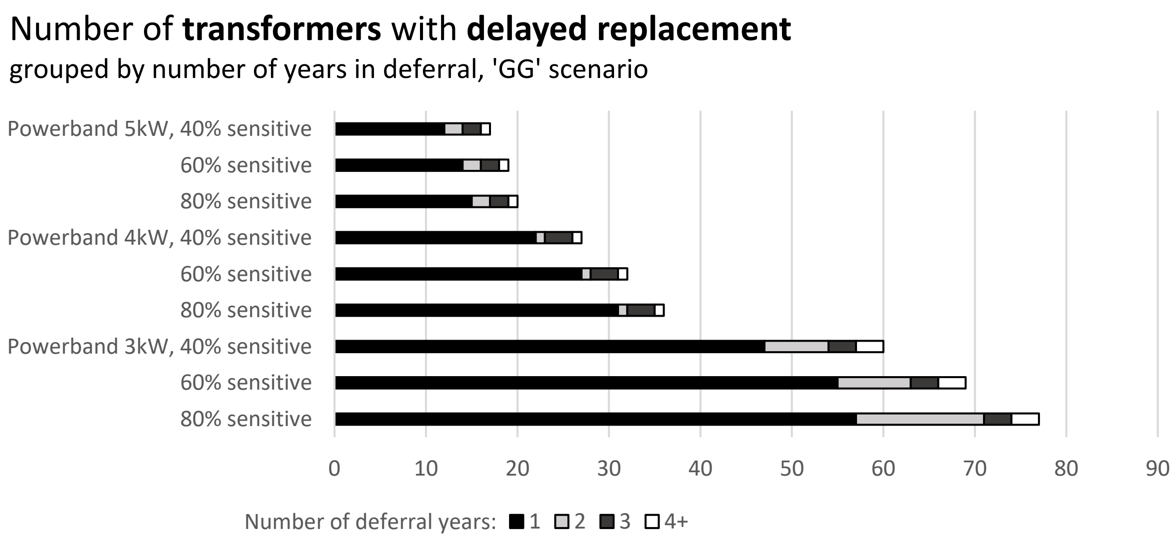

Figure 4.20 Transformer replacement deferral, 'GG' scenario

A similar comparison for the MV cables can be seen in Figure 4.21, which is based on data from Table V-B. In this case, it is expressed in kilometres of MV cable, for which replacement can be deferred. This time the maximal possible deferral period is only 2 years. However, in the majority of cases, this deferral happens in the last two years of simulation. Due to that, it might be worth to examine the numbers for longer simulations and more step technology penetration curves. Furthermore, for both the 4 and 3 kW powerbands, the biggest increases in possible deferral are being seen with the change from 40 to 60% of EV owners being sensitive.

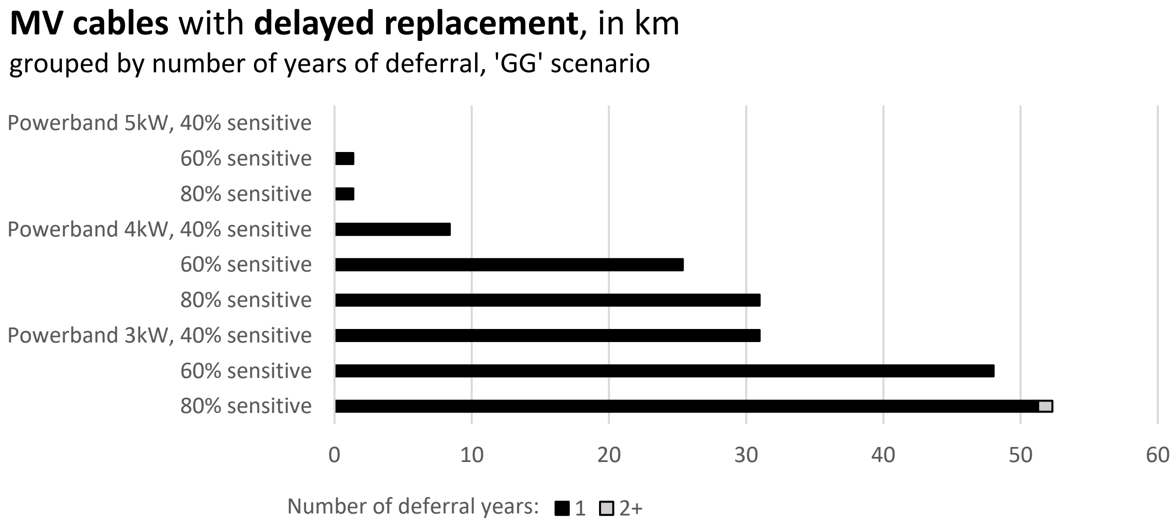

Figure 4.21 MV cables replacement deferral, 'GG' scenario

Lastly, the comparison for the LV cables can be seen in Figure 4.22, which is based on data from Table V-C. In this case, again the setting of the powerband becomes back the most important one determining the extent of deferral. Furthermore, it appears that each powerband setting doubles the number of km of LV cables of which replacement can be deferred. Moreover, within the same powerband, the number of elements which move to 3-year category appears to be the same. This cannot be said for the number of elements that move to 2-year category. For the powerband of 3 kW, it appears that this category grows faster than a 1-year one. Surprisingly the 60% sensitivity setting performs the worst in the 5 kW powerband. This is likely an anomaly, due to the stochastic nature of the simulation.

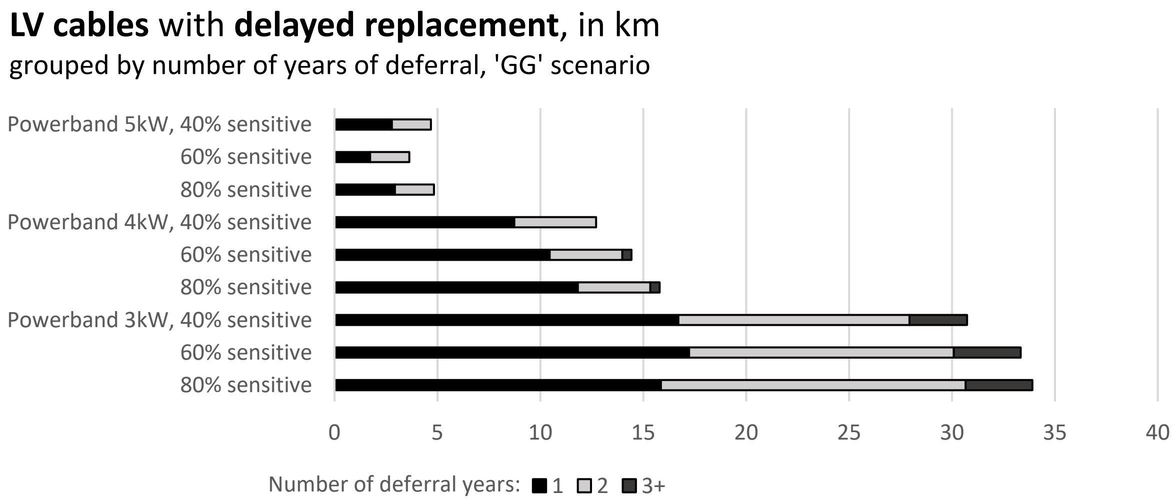

Figure 4.22 LV cables replacement deferral, 'GG' scenario

Overall the effects of the powerband tariff appear to be clearly visible. Based on the total number/length of the assets that are experiencing overloading it can be said that between 17% to 74% of transformers that experience overloading can gain at least 1 year of lifespan. For the MV cables, it is between 0% to 64% and for LV cables – 10 to 75%. These numbers, together with grid asset numbers are in Table 4.3.

Table 4.3 Deferral data for 'GG' scenario, (with percentages values of assets experiencing overloading)

	MV/LV transformers [-]	**MV cables** [km]	**LV cables** [km]
Total in simulation	2387	~2445.00	~2088.00
Experience overloading in 'GG' scenario	104 (100%)	81.23 (100%)	45.17 (100%)
Maximal possible deferral	77 (74.0%)	52.32 (64.4%)	33.91 (75.1%)
Minimal possible deferral	17 (16.3%)	0.00 (0.0%)	4.69 (10.4%)

A similar set of charts can be produced for '50' scenario. The assets with delayed replacement can be seen in Figure 4.23 toFigure 4.25. For this scenario, a higher number of assets can be replaced later and longer deferral times can be seen, even when comparing the percentages of possibly deferred assets (in relation to assets experiencing overloading). In the 'GG' scenario, deferral of asset replacement was mainly visible only for last years of simulation. In '50' scenario with faster adoption rates, this impact can be seen faster, and possibly true lengths of deferral period can be seen.

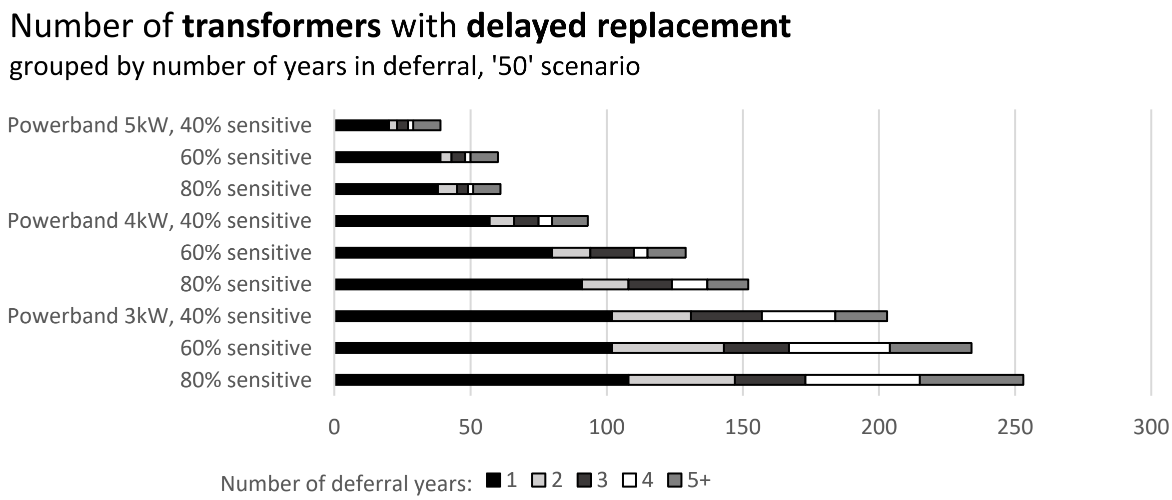

Figure 4.23 Transformer replacement deferral, '50' scenario

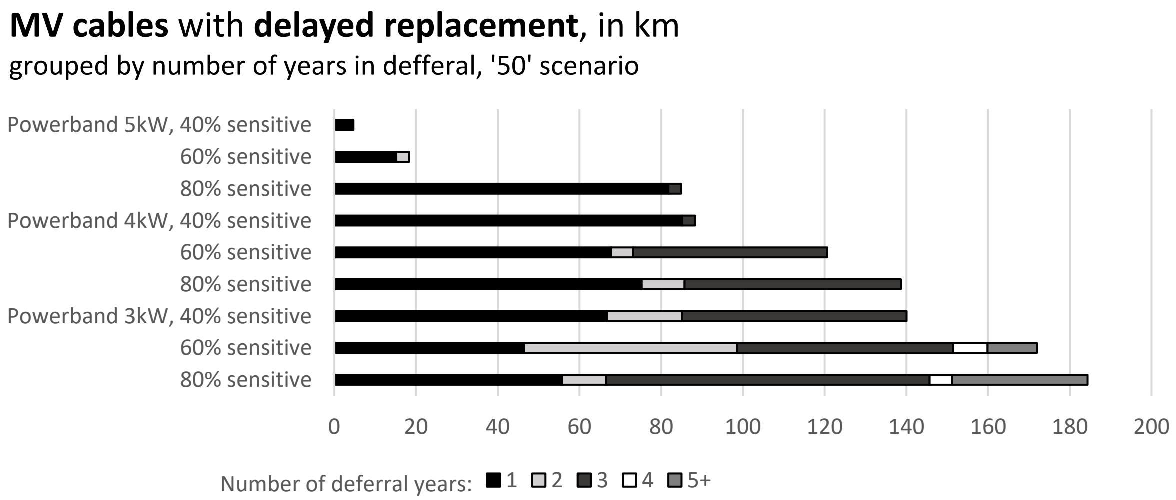

Figure 4.24 MV cables replacement deferral, '50' scenario

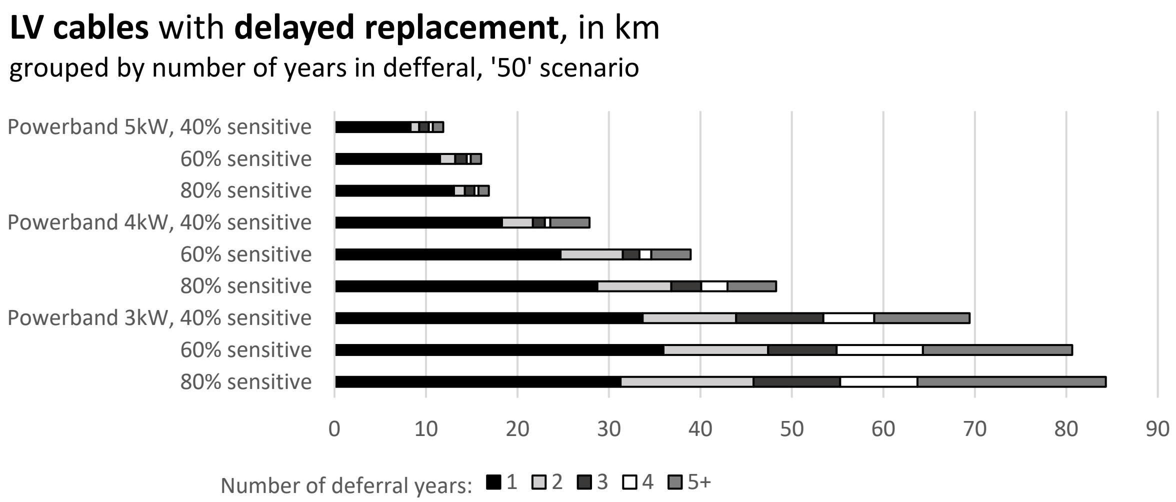

Figure 4.25 LV cables replacement deferral, '50' scenario

A summary of these results for '50' scenario can be seen in Table 4.4.

Table 4.4 Deferral data for '50' scenario, (with percentages values of assets experiencing overloading)

	MV/LV transformers [-]	**MV cables** [km]	**LV cables** [km]
Total in simulation	2387	~2445.00	~2088.00
Experience overloading in '50' scenario	317 (100%)	232.16 (100%)	102.46 (100%)
Maximal possible deferral	253 (79.8%)	184.34 (79.4%)	84.31 (82.3%)
Minimal possible deferral	39 (12.3%)	4.66 (2.0%)	11.88 (11.6%)

With the knowledge that there definitely are assets, which replacement can be deferred it might be worth to translate those number into the deferred investments for DSO.

5. Economic analysis

5.1. Introduction

For the economic analysis the same networks, as in the previous chapter, were analysed. The same component costs as in Scenariotool were taken to conduct this analysis. These costs are as following:

- Transformer (with the possibility of expanding substation): 15 000 €. This cost includes a transformer (8 000 €), and the possibility of having to expand substation (20-40 k€). This number is taken with the assumption that in some cases there will be a need for a new substation.
- MV cable: 120 000 €/km (includes work costs)
- LV cable: 100 000 €/km (includes work costs)

These numbers are averaged ones used by Enexis, as an in-depth analysis of the sizing, assessment and costs of the optimal investment options is out of the scope of this work. Moreover, this analysis will be done based on the difference in yearly cumulative asset replacement costs. Whether these costs are final or not depends on the expected penetrations of technologies in the future, with further integration of new technologies they are subject to change These numbers will be converted to present values. This difference, which can be also defined as a postponed investment, will be referred to as saving.

5.2. Results

To prevent information overload in graphs, it was decided to present a range of possible savings (as results from other settings sets are contained within it), instead of all results separately. Furthermore, it needs to be stressed that the savings from the introduction of the tariff are before any costs related to it (e.g. curtailment) and also don’t take into account the income for the grid operator from possible powerband tariff.

The chart that presents a possible range of savings for ‘GG’ scenario can be found in Figure 5.1. Based on its data it can be determined that possible savings in the last year of simulation range from 1.1 to 8.1 million € for simulated networks, depending on the powerband settings. To give some perspective, cumulative costs for the base scenario without flexibility amount to 23.7 million €. Unfortunately, due to the heterogeneous nature of these networks extrapolation of this result to the whole network might not yield the correct figure. For this reason, it would be preferable to run the scenarios with extreme settings for the entire network. However, at the time of finishing this thesis, it was not yet possible to do that, due to the data quality issues. Those costs are put into comparison with costs in case of not introducing a tariff by showing the same range of savings, this time in the percentage of costs for the baseline scenario in Figure 5.2.

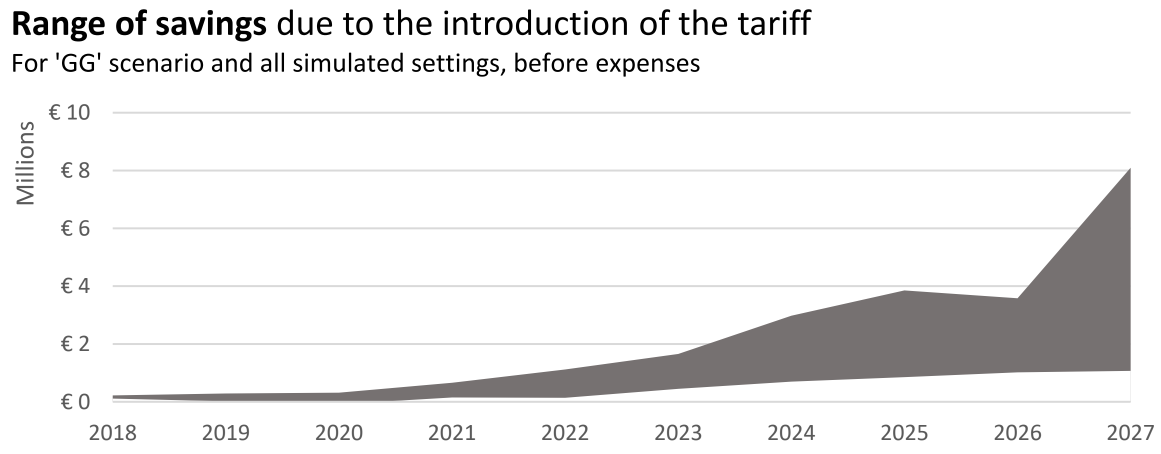

Figure 5.1 Range of possible savings due to the tariff. 'GG' scenario, for all settings.

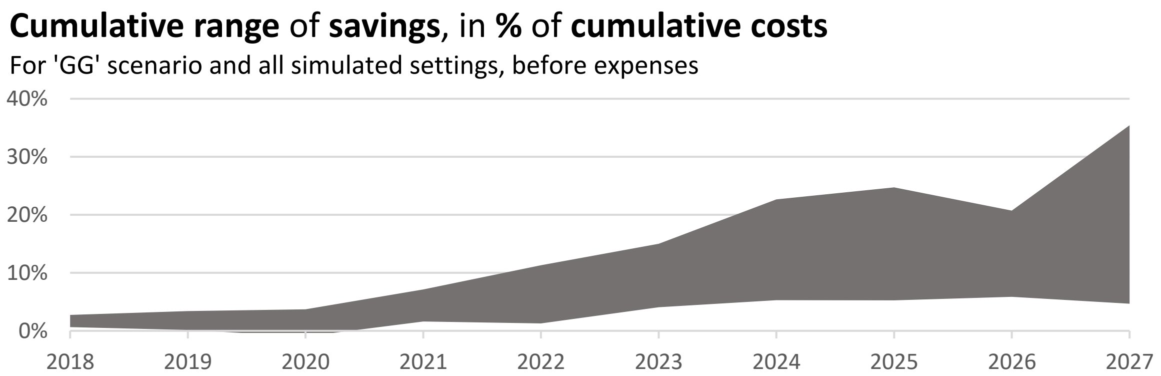

Figure 5.2 Range of possible savings due to the tariff in %. 'GG' scenario, for all settings.

Based on Figure 5.1, growth in minimal savings, starting in 2022, is rather gradual. For the maximum of this range, the amount of savings changes much more rapidly and experiences decreases.

While trying to find more information it might be worth checking which types of assets contribute towards the savings. This information, in averaged values from all 9 settings sets of simulation, can be found in Figure 5.3. Based on it, up to 2023 majority of savings comes from the deferred replacement of LV cables. After this year, savings from MV cables and transformers start to appear. For the latter, the percentage does not exceed 8 during the examined period. However, for MV cables, substantial growth in the contribution to savings can be seen for the year 2027. This is expected, as it was already explained that in the 'GG' scenario deferral of investments into MV cables becomes possible only in the last two years of simulation. Within all scenarios with stricter powerbands, LV cables still affect the savings the most. However, in case of the least strict setting MV cables no more contribute to the savings. This is due to the fact that they do not present an opportunity for later replacement. Furthermore, this was already seen in Figure 4.21. For the strictest setting, a much higher percentage of savings, start to come from the deferred replacement of MV cables. This percentage arrives at 43% in the last year of simulation.

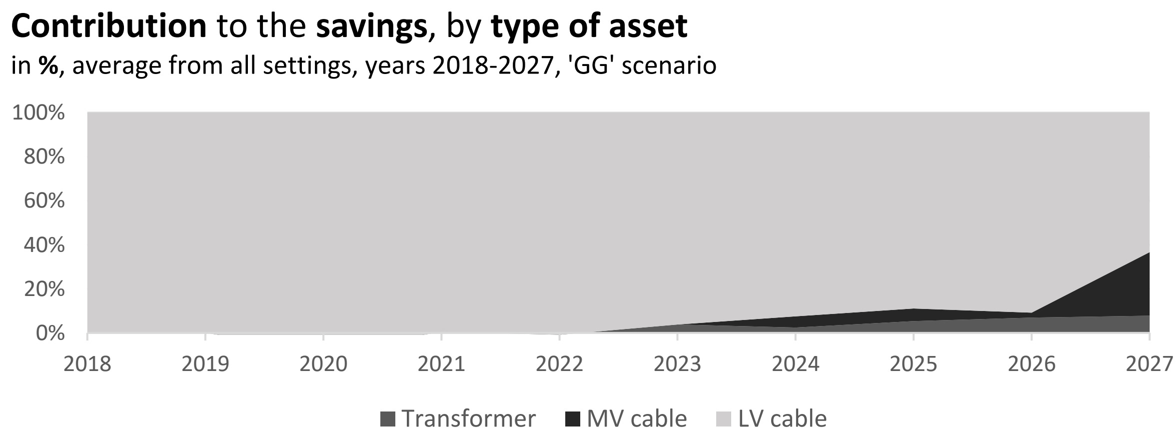

Figure 5.3 Contribution to the savings, by types of asset, 'GG' scenario

Another comparison can be done for the numbers of assets that need replacement based on the Summer and Winter values. Here, Summer values more likely represent loading from the production of energy from PV panels and Winter from the EV and HP demand. For an asset to contribute to the 'total' number, it needs to contribute to savings in both seasons, or contribute in one season and not experience overloading or voltage limit violation in the other season.

In the case of transformers, it appears that the majority of cost reductions come from summer, most likely from PV curtailment. The same is true for LV cables. However, at the MV cable level, it appears that for bands lower than 5 kW almost 100% of savings comes from the reduction in winter loading. This can be seen in Figure 5.4, while charts with other scenario settings can be seen in Appendix VI: Economic data.

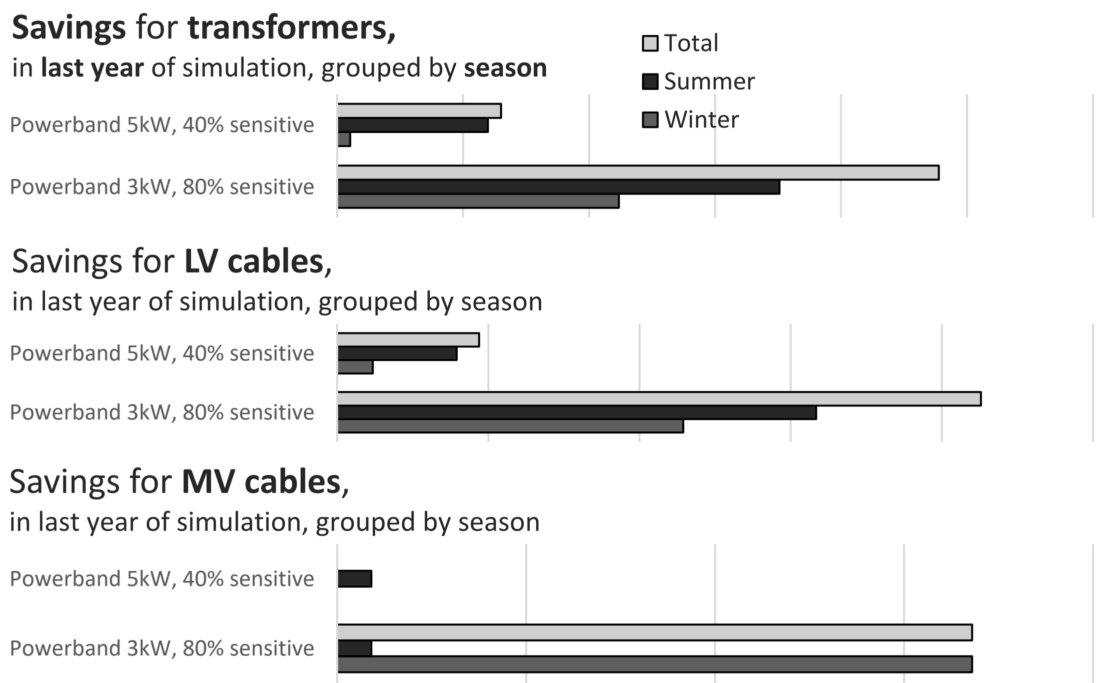

Figure 5.4 Cost reduction on assets in last year of simulation, by season, 'GG' scenario

A similar set of charts can be produced for '50' scenario. The overall range of cost reduction can be seen in Figure 5.5. In this case, due to the higher number of elements for which deferred replacement is applicable, the possible savings also grow to a range of 1.7 to 16.7 million €. In the case of the '50' scenario, the base costs (without flexibility) amount to 50.3 million €. However, some assets, for which utilization was extended, start to reach their maximum loading values – this is correlated to the plateau in maximum cost reduction in years 2027-2029. Still, due to the fact that there is hardly any change means that deferred investment into other assets starts to come into place. Again, those costs are put into comparison with costs in case of not introducing a tariff by showing the same range of savings, this time in the percentage of costs for the baseline scenario in Figure 5.6.

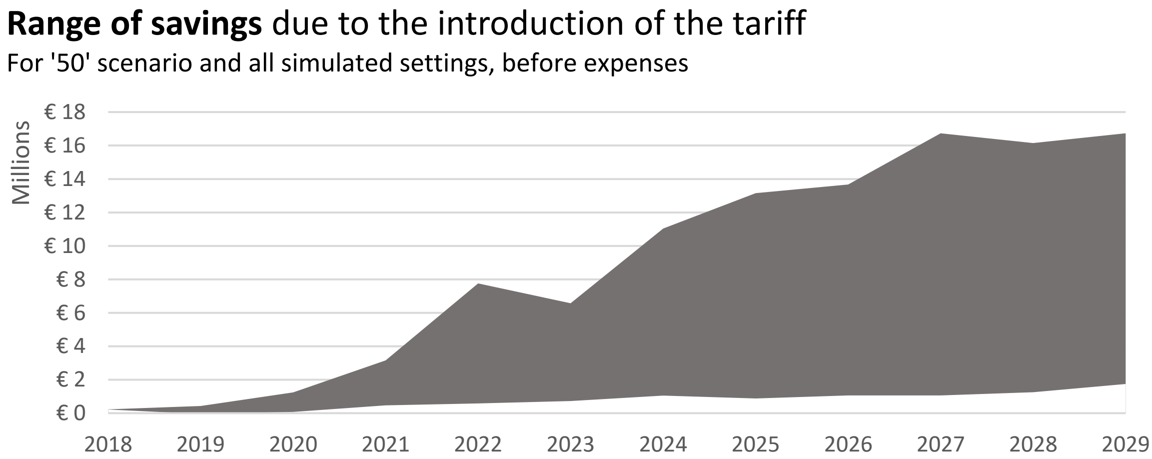

Figure 5.5 Range of possible savings due to the tariff. '50' scenario, for all settings.

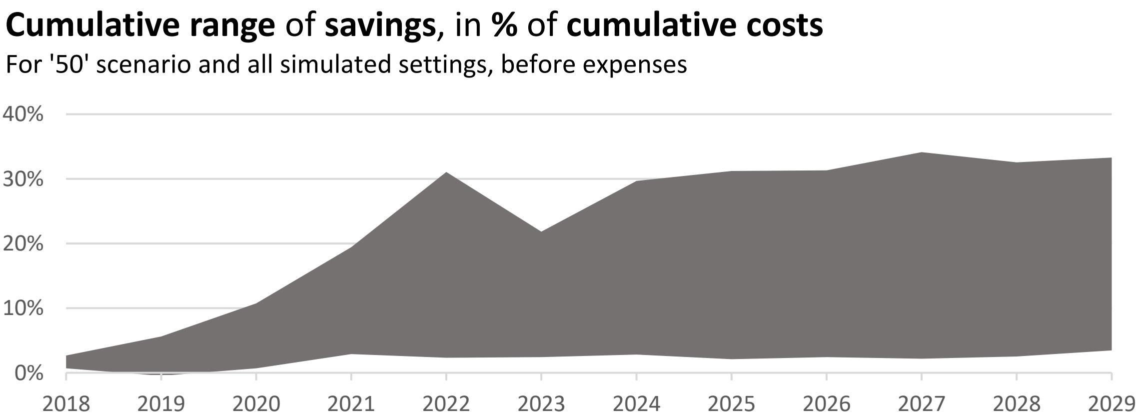

Figure 5.6 Range of possible savings due to the tariff, in %. '50' scenario, for all settings.

After analysing which assets contribute to the cost reduction in this scenario (Figure 5.7), it can be said that in this scenario powerband tariff becomes more efficient at increasing lifespan of MV cables. Moreover, it appears that dips in the cost reduction seen in the years 2023 and 2028 seen in Figure 5.5 might be attributed to the MV cables reaching their limits, even with tariff in place.

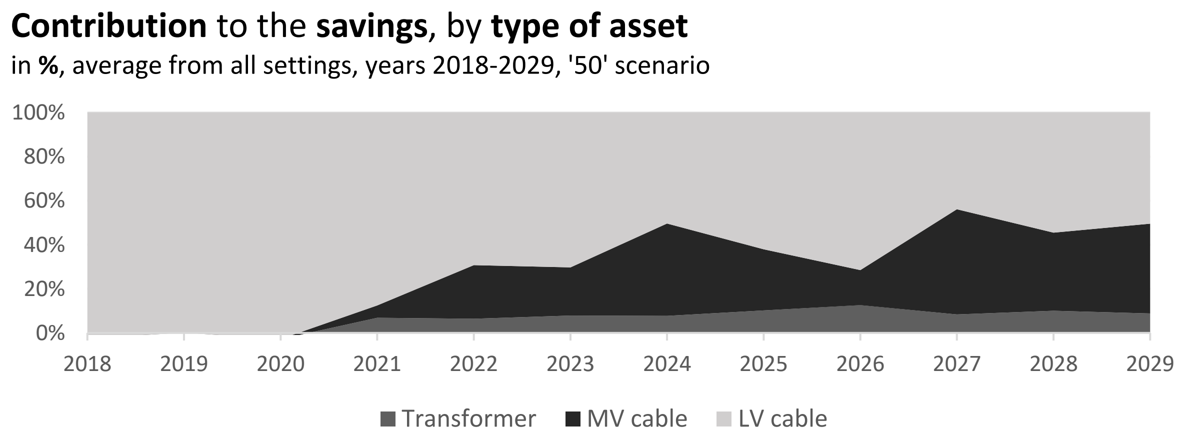

Figure 5.7 Contribution to the savings, by types of asset, '50' scenario

Results from this section show that the intended effect of the tariff – deferral in asset replacement – is reached. The exact impact of a tariff depends on the chosen scenario and settings of the simulation. However, it appears that with the chosen powerband settings (3, 4 and 5 kW) result for a lower sensitivity of a higher band is usually equal to one for a higher sensitivity of a lower band (40 vs 80%). Moreover, the majority of cost reduction comes from the cables, both LV and MV, and the impact of the tariff on LV cable deferral is seen faster than the impact on MV cable loading.

Based on the simulation results for the 'GG' scenario and chosen set of networks, powerband tariff was able to postpone between 4.7 and 35.4% of costs related to the grid assets replacement. For the '50' scenario this number was ranging from 3.5 to 33.3%. These numbers and figures for previous years can be seen in Figure 5.2 and Figure 5.6[4].

These ranges correspond to respectively 1.1÷8.1 and 1.7÷16.7 million € for 6 simulated networks from over 120. They consisted of 2387 MV/LV transformers, 2445 km of MV cables and 2088 km of LV cables, according to the provided data. This corresponds to 4.4% of all transformers, 5.5% of MV network length and 5.7% LV network length that Enexis operates [64].

6. Conclusions, contributions and recommendations

6.1. Conclusions

The objective of this thesis was twofold, with the first part related to theoretical research and flexibility activation method comparison and the second part being the implementation of the chosen method in Enexis' energy transition scenario analysis tool together with an evaluation of the impact of this method.

First, the research over the household electricity consumption flexibility was conducted and the optimal method was selected. Optimal was defined as one that, according to the corresponding research question, would provide a sufficient amount of flexibility in a reliable way for acceptable cost and would be viable from both a technical and legislative perspective. This selection was further influenced by the perspective of the Distribution System Operator. This means that flexibility is activated in order to shave consumption peaks at the network asset level. This, in turn, allows to reduce current congestion and also decreases the chance of over or undervoltage occurring. As an end

[4] Data separate for all scenario settings can be found in Appendix VI: Economic data in Figure VI-I and Figure VI-J.

result, this allows for the deferral of asset replacement with direct savings for the Distribution System Operator.

With these requirements in mind and based on the comparison done in section 3.6, the powerband tariff was chosen as one which fared optimally, when taking all the requirements in mind. Moreover, this method presented viability for the planning period that Scenariotool operates on, that is about 10 years into the future. The exact type of powerband tariff was chosen to be the one with a threshold below which energy consumed has ‘normal’ price and above it has a higher price. For the PV production, it was decided that with the current market setup of net-metering, the introduction of excessive power into the grid should be disincentivized. However, it needs to be taken into consideration that other activation methods also present an opportunity for potentially unlocking additional flexibility when current barriers to their introduction are overcome.

Then, the selected flexibility activation method was modelled in a way that allowed for the implementation in the Enexis’ Scenariotool. Based on the taken assumptions and results from conducted pilot projects, the main optimized loads were electric vehicles and photovoltaic panels, due to their relatively high impact on asset loading. Furthermore, a set of assumptions dictated by the available data and performance requirement was made. The households’ sensitivity to the tariff is not simulated, as there was no way to verify it, but rather put as a variable, so it could be examined with later projects. The impact of the chosen activation method, powerband based tariff, was examined from household level up to the level of Enexis’ network. Then, the costs that Enexis can face due to the overloaded (or experiencing over-/undervoltage) assets were examined for scenarios with and without activation of flexibility. Those costs were transformed to the present values and further examined by asset type and season.

The created model is informative when it comes to the possible impact of such flexibility activation method and it provides information about opportunities for deferral of investments into new assets due to exceeded operational parameters of current and voltage. Moreover, the requirement related to the performance impact of added functionality was also fulfilled. With additional calculations simulation took about 2.75 times as long as the same one without flexibility.

In conclusion, this project identified optimal method, from the viewpoint of DSO, for activation of flexibility from the households, presented model that modifies residential loads according to this method and performed an economic evaluation of the tariff’s impact onto the part of DSO’s grid.

6.2. Contributions

Contributions of this graduation project can be split between scientific and practical.

As for the first category, this report includes a comparison between flexibility activation methods from the perspective of the Distribution Grid Operator. It first discusses the theory behind each method and brings up results, conclusions and recommendations from pilot projects realized in the Netherlands and neighbouring countries. Summary of those findings is given in the form of the comparison between those methods, giving arguments for grading methods within each category. Moreover, this report proposes a computationally efficient method for modelling said flexibility – this method is able to process 1000 iterations of load profiles for 100 electric vehicles considering profiles from 100 houses, photovoltaic systems and heat pumps and then process photovoltaic profiles taking into account other loads in, on average, 1.6 seconds. This allows for the use of the proposed model in large scale analysis in feasible time scales, something that would not be possible with most of the current approaches related to modelling flexibility.

From the practical side of view, the conducted research allowed for the identification and, after consultation, verification of opportunity that power-based tariffs offer for DSO dealing with rapid changes in household energy consumption. Based on that, an algorithm was developed and extensively tested in order to allow for easy implementation in Enexis' Scenariotool. Then further work was done on the performance optimization in order to provide a scalable solution – one that was be able to operate within the presented specifications. After that, it was integrated into Enexis energy transition scenario analysis tool and is intended to be used further, with active interest from other projects inside Enexis. Integration into the Scenariotool allowed to examine the impact of the flexibility activation method on the network scale, as well as assess the possible impact of deferred investments into the network assets.

Furthermore, several modelling and performance improvements were done to how Scenariotool creates profiles of EV charging. This is further discussed in Appendix IV: Fast EV profile generation.

6.3. Recommendations

Several areas for improvement and/or continuation of work can be brought up. These will be again grouped into scientific and practical categories

From the scientific standpoint:

- **Variation of tariff threshold values in time** – As it was already brought up, more complicated tariffs or the approach resembling variable capacity method could be easily implemented. It would require a change in how bandwidth threshold value is handled but based on quick tests it should be possible. This could allow for assessing whether more complicated tariff would be more effective at reducing peak loading. This method could also serve as quick verification for variable capacity tariff, if the cap in one time period is not producing new peaks, and in turn increasing overloading, with chosen lowered capacity power and time period.
- **Examination of effects of another flexibility activation method, if used 'on top of' tariff** – One of the ideas that were examined during this project was an approach with multiple activation methods of flexibility. Due to the previously defined scope, requirements and constraints it was not followed on. However, the idea seems attractive, due to the fact that in this way the flaws of methods operating separately could be minimized. Examination of how another activation method used after tariff affects the flexibility and whether the size of the market would be sufficient for it, might be worth following on.
- **Addition of heat and household appliance related flexibility** – While heat-related flexibility was decided not to be examined, due to the low potential gains, it might be worth including it in the model, in order to verify this claim at the asset level. Similar action can be recommended for the other electrical appliances within the household. Furthermore, new pilot projects dealing with this area should be followed in order to examine whether current results were not hampered by the low technology readiness of solutions used in those.

From the practical standpoint:

- **Simulation of tariff effects for the entire Enexis' network and examination of different scenario parameters** – In this thesis, only about 5% of the entire Enexis' network was examined. It might be beneficial to re-examine the results for bigger network area. Furthermore, the analysis could be repeated for different energy transition scenarios. As it was already seen simulated scenarios does not differ that much when it comes to the relative network values – this could be further verified. Examination of different scenarios could bring more information on what the tariff's effects with different penetration of new technologies would be. The same goes for scenario settings – how even more different bands and sensitivity values affect the flexibility gain. Finally, it could be worth examining situations where more electric vehicle owners use higher speed chargers.

- **Examination of sensitivity value in real life** – Should the implementation of the tariff be considered, it would be beneficial to examine the response of households to it – especially how their behaviour can be translated into the sensitivity value. This could be then used for examination of tariff effectiveness from the perspective of DSO.
- **More in-depth analysis of tariff economic effects** – As it was explained in Section 5: Economic analysis, the calculation of the monetary benefit of the tariff was done without taking into account the costs related to its introduction or the potential change in the DSO income from the new tariff design. Should the latter become more defined, it would be beneficial to examine the net benefit of the tariff.

Fitting into both categories:

- **Data quality improvement** – As one of the issues that prevented the simulation of the entire network was data quality, specifically problems with network files used for load flow simulation it is recommended to address it.
- **Examination of how many sensitive users are required to prevent overloading** – Another idea that was not further examined is adding functionality to the tool that would allow for examination of sensitivity needed to prevent overloading per asset. It should be possible to implement such functionality for the LV network, based on comparisons between the asset nominal current carrying capacity and numbers of assets with flexible profiles. Furthermore, a similar 'grid sensitivity' analysis could be done for the number of EVs.
- **Examination of results for rural and urban grids** – While the goal of this thesis was to examine the network as a whole (despite the existing data quality issues) the further research could contain more detailed analysis, one which would examine rural and urban grids separately. This could give additional insight into the exact sources of the problems and could further inform a decision about tariff design.
- **Additional constraints related to the EV charging and examination of unfinished charging sessions** – In the current implementation, trip data from OViN research is used for generation of electric vehicle profiles with a limited number of restriction on its output. To give an example, the energy that is charged is not limited in any way, this can lead to situations where EV is scheduled to charge more energy than any model available in the market is able to 'hold'. Addition of some checks related to the length of the stay or maximal possible charge within the stay period could improve the accuracy of the model. For this project it was not done, as deciding on exact values would require even more research and validating them. However, it might be possible to examine this area more in the future. Moreover, the examination of the effects of flexibility on the number of unfinished charging sessions and uncharged EV battery capacity could give additional insights.

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Appendix I Inputs and outputs

With these assumptions in place, the model takes the following inputs:

- Load profiles of houses in LV network – Load profiles and a number of the houses for the currently simulated network. Data for this input is passed from the Scenariotool, which obtains those values from the Enexis' database.
- Number of EVs – Load profiles and a number of the EVs for the currently simulated network. Data for this input is passed from the Scenariotool, which obtains those values from the Scenariotool adoption rates per asset.
- Load profiles of PVs – Load profiles and a number of the PVs for the currently simulated network. Data for this input is passed from the Scenariotool, which obtains those values from the Scenariotool adoption rates per asset.
- Load profiles of HPs – Load profiles and a number of the HPs for the currently simulated network. Data for this input is passed from the Scenariotool, which obtains those values from the Scenariotool adoption rates per asset.
- Yearly electricity consumption at the asset level –yearly electrical energy consumption for the currently simulated asset. Data for this input is passed from the Scenariotool, which obtains those values from the Enexis' database.
- EV charging speed – Maximal power accessible for the EV chargers, uniform for the simulation, given in kW.
- Powerband value – Threshold value (step) of power, outside of which energy usage will be considered to be out of the band. Applicable for both consumption and production (symmetrical). Specified by the user of the model.
- Sensitivity – Percentage of the EV owners that would adhere to the tariff. Uniform for the simulation, specified by the user of the model.
- EV trip data – Transformed data from OViN research [13]. Data consists of arrival and departure times together with covered distance within one day for each reported entry.

And the following outputs:

- New EV profiles – transformed EV profiles to include the flexible response of a sensitive subset of EV owners and nonflexible for the insensitive.
- Curtailed PV profiles – PV profiles with curtailment at the household connection with the network. Curtailed to the powerband value for energy output. Follow the format of the Scenariotool data.
- Energy consumption data (optional) – optional data output specifying the energy output inside/outside the band. Contains data on the before and after application of flexibility, production and consumption, outside and inside the band and specified percentiles of the obtained from Monte Carlo approach. Aggregated to sums per simulated asset.
- Amount of uncharged energy (optional, not integrated into the Scenariotool) – additional data with numbers on uncharged energy per household for each Monte Carlo iteration.

Appendix II Unfinished charging sessions

In this appendix an -examination of results of unfinished charging sessions in relation to the size of the powerband will be conducted. This examination was done on the basis of 100 000 charging sessions from the model assigned to houses with yearly energy consumption of about 5000 kWh for winter period. Moreover for half of those sessions corresponding household also used an electric heat solution. The analysis was done with assumption that 100% of EV owners will be sensitive to the tariff and they will have access to charger with maximal power of 3.6 kW. These settings should result in close to extreme, save for 100% penetration of electric heating, situation where likelihood of unfinished session is very high.

First of, the percentage of unfinished charging sessions is compared in Figure II-A. The changes for bands 5kW and 4kW are not bigger than 1.4 percent points over the baseline (inflexible charging). However for band of 3kW this number already about doubles and for 2kW quadruples.

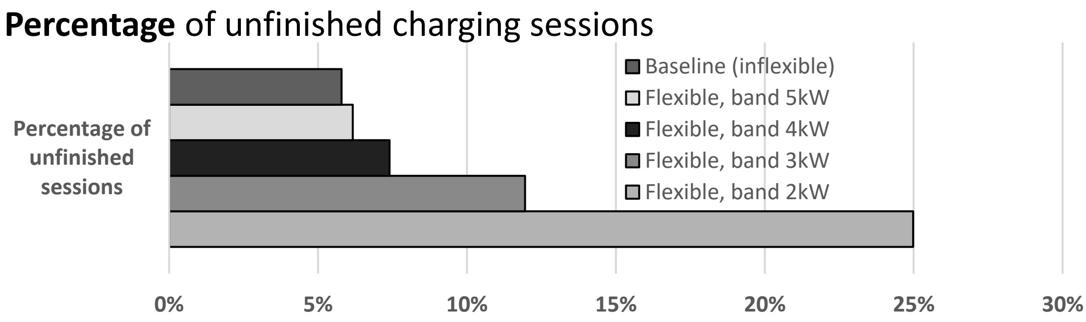

Figure II-A Comparison of percentage of sessions being unfinished

Then relevant metrics (lower quartile, median, upper quartile, mean) of absolute values for uncharged capacities are shown in the Figure II-B. When examining these values it can be seen again that for the lower bands (2 and 3 kW) the uncharged capacities are generally higher, which is to be expected. However for band of 5kW there is barely any difference (it is within the error margin of average from different simulations).

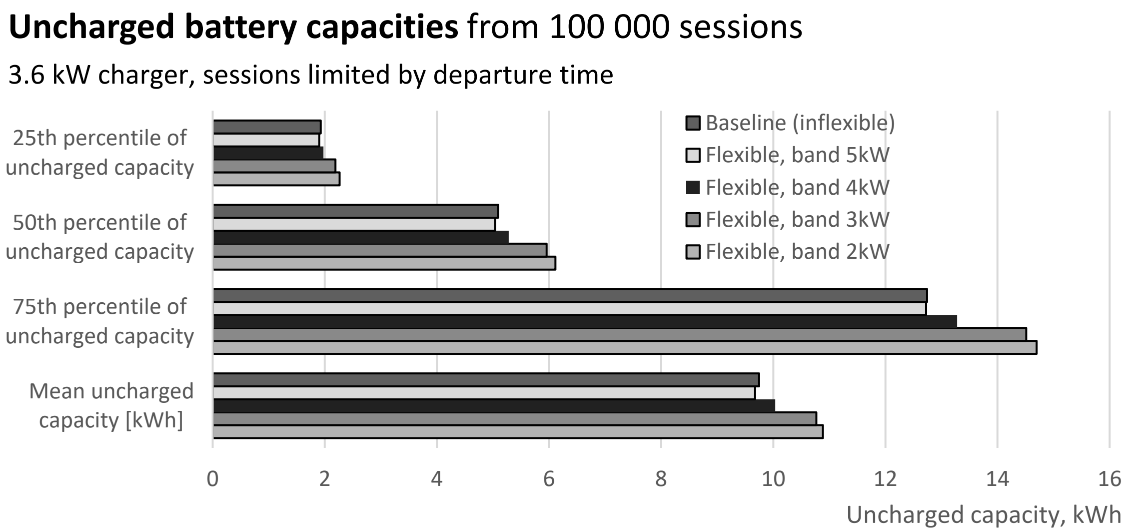

Figure II-B Comparison of uncharged battery capacities, absolute values

The difference discussed for Figure II-B becomes more pronounced when shown in values relative to baseline (defined as 100%) in Figure II-C.

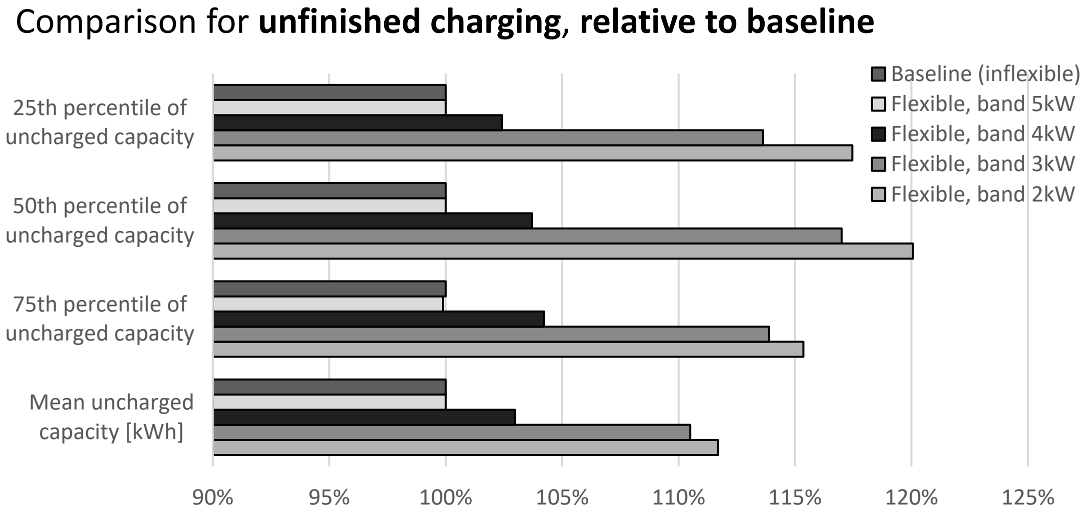

Figure II-C Comparison of uncharged battery capacities, values relative to baseline

Based on those values it appears that powerband of 2kW is too strict and might impact comfort of the EV owners and/or result in situation where less of them would be sensitive to the tariff.

Appendix III Technology adoption scenarios

Following scenarios were chosen:

- 'GG' – scenario of continuing, gradual growth, from the current values. Up to and including the year 2027.
- '50' – scenario of quick growth, that stabilizes at 50% penetration in the year 2029 for all technologies.

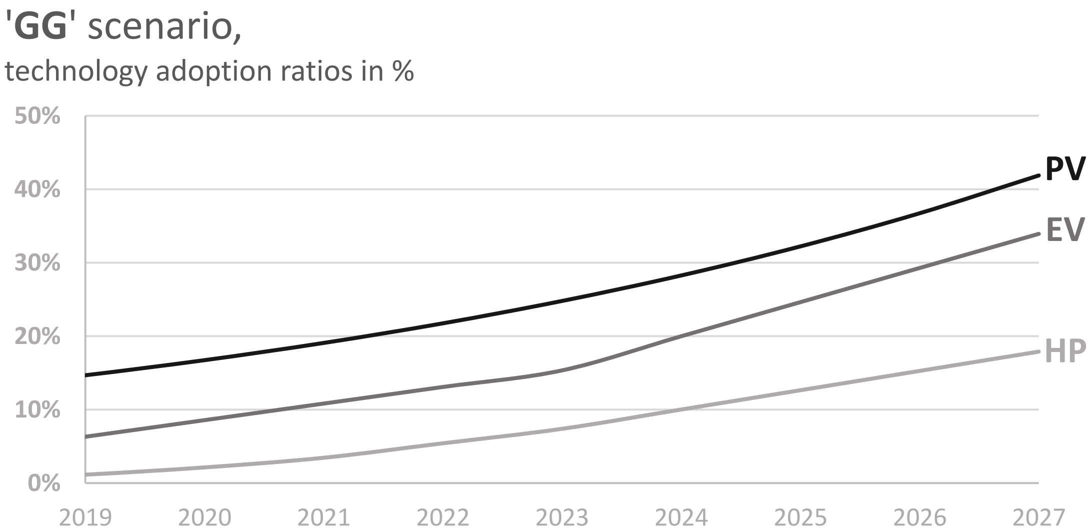

Figure III-A 'GG' scenario technology adoption ratios

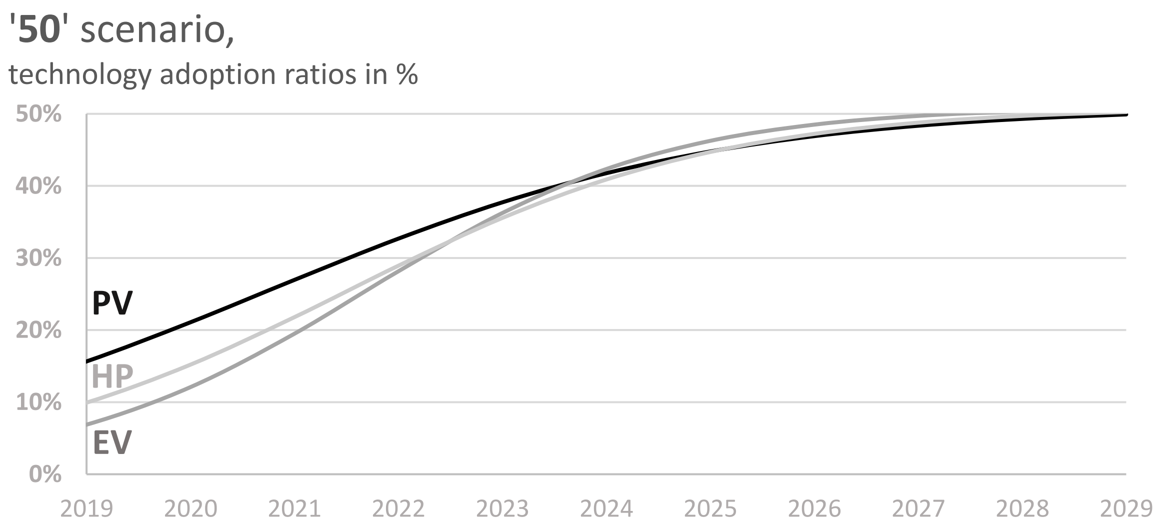

Figure III-B '50' scenario technology adoption ratios

Table III-A Data for scenario adoption

Scenario	Technology	Year 2018	Year 2019	Year 2020	Year 2021	Year 2022
'GG'	PV	12.9%	14.7%	16.7%	19.1%	21.7%
	EV	4.0%	6.3%	8.6%	10.8%	13.1%
	HP	0.5%	1.1%	2.1%	3.4%	5.4%
'50'	PV	11.1%	15.7%	21.1%	27.0%	32.7%
	EV	3.7%	6.9%	12.1%	19.5%	28.2%
	HP	6.2%	9.9%	15.2%	21.8%	28.9%

Scenario	Technology	Year 2023	Year 2024	Year 2025	Year 2026	Year 2027
'GG'	PV	24.8%	28.3%	32.2%	36.7%	41.9%
	EV	15.3%	20.0%	24.6%	29.3%	33.9%
	HP	7.4%	10.0%	12.6%	15.3%	17.9%
'50'	PV	37.7%	41.8%	44.8%	46.9%	48.3%
	EV	36.2%	42.3%	46.3%	48.5%	49.7%
	HP	35.6%	40.9%	44.7%	47.2%	48.8%

Scenario	Technology	Year 2028	Year 2029
'GG'	PV	-	-
	EV	-	-
	HP	-	-
'50'	PV	49.3%	49.9%
	EV	50.3%	50.7%
	HP	49.7%	50.3%

Appendix IV Fast EV profile generation

For the purpose of quick generation of EV profiles with options of varying charging speed and driving efficiency additional functionality was developed.

First, OViN dataset [13] was transformed in a similar way as in [12]. That is, unique trips done by cars were transformed into a single daily distance and rounded arrival and departure times (to a 15-minute interval). Then marginal Gaussian mixture distributions were fitted to this data, CDF transformation was applied to obtain uniform distributions. Lastly, copula functions were fitted to obtain correlated data structures and random samples were generated from this data.

At this point, the input set of data consisted of random by correlated with each other values for departure quarter, arrival quarter and length of the trip. This data was further cleaned to remove 'impossible' trips – ones that had negative duration or distance and ones with average speed higher than 150 km/h.

At this point based on the driving efficiency value $\eta_{driving}$, in km/kWh, trip distance d_{trip} was converted into to energy required to charge E_{charge} and time required to charge T_{charge} based on knowledge of charging speed CC_{max}. The maximum length of the charging session was limited to a full day (95 quarters). This can be shown with the following equations:

$$E_{charge} = \frac{d_{trip}}{\eta_{driving}} \tag{A1}$$

$$T_{charge} = \begin{cases} \left\lfloor \frac{E_{charge}}{CC_{max}/4} \right\rfloor, & \frac{E_{charge}}{CC_{max}/4} \leq 95 \\ 95, & \frac{E_{charge}}{CC_{max}/4} \leq 95 \end{cases} \tag{A2}$$

Next, the temporary load profile is created that still doesn't take into account arrival time but contains average 15-minute values with maximal possible charging speed until the EV batteries are fully charged (taking into account partial charge during the last quarter).

$$P^t_{charge} = \begin{cases} CC_{max}, & t < T_{charge} \\ E_{charge} - \sum_{t=0}^{T_{charge}} P^t_{charge}, & t = T_{charge} \\ 0, & t > T_{charge} \end{cases} \tag{A3}$$

At this point, it becomes possible to 'shift' the profiles so that arrival quarter $qArr$ corresponds to the first charging start. This shift is dependant on Python's Numpy package indexing approach. Indices corresponding to the quarters of an hour during a day, t, are modified based on the arrival quarter.

$$t_{shifted} = t - qArr \tag{A4}$$

$$P^t_{charge,shifted} = P^{t_{shifted}}_{charge} \tag{A5}$$

In this approach, the negative positions are counted from the end of an array and positive from the beginning. This results in an accurate charging profile. This approach was taken because it allows for very fast operation on big matrices. This is particularly beneficial in case of implementation in this project, because of the Monte Carlo simulation approach, in which each EV in simulated corresponds to 1000 load profiles.

Further improvements include limitation related to the departure time $qDep$ (which is assumed to be the same as previous day departure quarter). This was tested and found functioning. However, was not implemented finally in the Scenariotool. It can be described by following additional step that would be taken between A3 and A4:

$$qDep_{temp} = \begin{cases} qDep, & qDep \geq qArr \\ qDep + 95, & qDep < qArr \end{cases} \tag{A6}$$

$$P^t_{charge} = \begin{cases} P^t_{charge}, & t \leq qDep - qArr \\ 0, & t > qDep - qArr \end{cases} \tag{A7}$$

These additional conditions ensure that charging is limited to the most possible 'stay at home' time (assuming that there is a small variation in day to day departure times).

Appendix V Deferral data tables

In this appendix tables that contain data related to the asset deferral from section 4.5.3 Asset level will be included.

Table V-A Transformer deferral data, in no of transformers (and possibly substations), 'GG' scenario

			Years of deferral				
Scenario	**Mean of years of deferral**	**Total**	**5+**	**4**	**3**	**2**	**1**
Powerband **3kW**, **80%** sensitive	1.377	77	0	3	3	14	57
Powerband **3kW**, **60%** sensitive	1.333	69	0	3	3	8	55
Powerband **3kW**, **40%** sensitive	1.367	60	0	3	3	7	47
Powerband **4kW**, **80%** sensitive	1.278	36	0	1	3	1	31
Powerband **4kW**, **60%** sensitive	1.312	32	0	1	3	1	27
Powerband **4kW**, **40%** sensitive	1.370	27	0	1	3	1	22
Powerband **5kW**, **80%** sensitive	1.450	20	0	1	2	2	15
Powerband **5kW**, **60%** sensitive	1.474	19	0	1	2	2	14
Powerband **5kW**, **40%** sensitive	1.529	17	0	1	2	2	12

Table V-B MV cables deferral data, in km of cables, 'GG' scenario

			Years of deferral				
Scenario	**Mean of years of deferral**	**Total**	**5+**	**4**	**3**	**2**	**1**
Powerband **3kW**, **80%** sensitive	1.083	52.32	0.00	0.00	0.00	1.04	51.28
Powerband **3kW**, **60%** sensitive	1.000	48.04	0.00	0.00	0.00	0.00	48.04
Powerband **3kW**, **40%** sensitive	1.000	30.98	0.00	0.00	0.00	0.00	30.98
Powerband **4kW**, **80%** sensitive	1.000	30.98	0.00	0.00	0.00	0.00	30.98
Powerband **4kW**, **60%** sensitive	1.000	25.39	0.00	0.00	0.00	0.00	25.39
Powerband **4kW**, **40%** sensitive	1.000	8.40	0.00	0.00	0.00	0.00	8.40
Powerband **5kW**, **80%** sensitive	1.000	1.36	0.00	0.00	0.00	0.00	1.36
Powerband **5kW**, **60%** sensitive	1.000	1.36	0.00	0.00	0.00	0.00	1.36
Powerband **5kW**, **40%** sensitive	-	0.00	0.00	0.00	0.00	0.00	0.00

Table V-C LV cables deferral data, in km of cables, 'GG' scenario

			Years of deferral				
Scenario	**Mean of years of deferral**	**Total**	**5+**	**4**	**3**	**2**	**1**
Powerband **3kW**, **80%** sensitive	1.582	33.91	0.00	0.00	3.24	14.80	15.86
Powerband **3kW**, **60%** sensitive	1.515	33.34	0.00	0.00	3.24	12.87	17.22

Scenario	Mean of years of deferral	Total	Years of deferral 5+	4	3	2	1
Powerband **3kW**, **40%** sensitive	1.483	30.73	0.00	0.00	2.80	11.23	16.70
Powerband **4kW**, **80%** sensitive	1.323	15.79	0.00	0.00	0.45	3.53	11.82
Powerband **4kW**, **60%** sensitive	1.357	14.43	0.00	0.00	0.45	3.53	10.46
Powerband **4kW**, **40%** sensitive	1.375	12.71	0.00	0.00	0.00	3.97	8.73
Powerband **5kW**, **80%** sensitive	1.417	4.83	0.00	0.00	0.00	1.90	2.93
Powerband **5kW**, **60%** sensitive	1.556	3.63	0.00	0.00	0.00	1.90	1.73
Powerband **5kW**, **40%** sensitive	1.417	4.69	0.00	0.00	0.00	1.90	2.79

Table V-D Transformer deferral data, in no of transformers (and possibly substations), '50' scenario

Scenario	Mean of years of deferral	Total	Years of deferral 5+	4	3	2	1
Powerband **3kW**, **80%** sensitive	2.561	253	38	42	26	39	108
Powerband **3kW**, **60%** sensitive	2.466	234	30	37	24	41	102
Powerband **3kW**, **40%** sensitive	2.286	203	19	27	26	29	102
Powerband **4kW**, **80%** sensitive	2.112	152	15	13	16	17	91
Powerband **4kW**, **60%** sensitive	2.070	129	14	5	16	14	80
Powerband **4kW**, **40%** sensitive	2.237	93	13	5	9	9	57
Powerband **5kW**, **80%** sensitive	2.230	61	10	2	4	7	38
Powerband **5kW**, **60%** sensitive	2.233	60	10	2	5	4	39
Powerband **5kW**, **40%** sensitive	2.821	39	10	2	4	3	20

Table V-E MV cables deferral data, in km of cables, '50' scenario

Scenario	Mean of years of deferral	Total	Years of deferral 5+	4	3	2	1
Powerband **3kW**, **80%** sensitive	2.629	184.34	33.19	5.46	79.23	10.77	55.68
Powerband **3kW**, **60%** sensitive	2.333	171.91	12.04	8.42	52.91	52.09	46.45
Powerband **3kW**, **40%** sensitive	1.920	140.04	0.00	0.00	54.97	18.40	66.67
Powerband **4kW**, **80%** sensitive	1.792	138.62	0.00	0.00	52.91	10.50	75.21
Powerband **4kW**, **60%** sensitive	1.714	120.63	0.00	0.00	47.49	5.42	67.72
Powerband **4kW**, **40%** sensitive	1.143	88.26	0.00	0.00	3.12	0.00	85.14
Powerband **5kW**, **80%** sensitive	1.154	84.86	0.00	0.00	3.12	0.00	81.74
Powerband **5kW**, **60%** sensitive	1.167	18.30	0.00	0.00	0.00	3.12	15.18
Powerband **5kW**, **40%** sensitive	1.000	4.66	0.00	0.00	0.00	0.00	4.66

Table V-F LV cables deferral data, in km of cables, '50' scenario

Scenario	Mean of years of deferral	Total	Years of deferral 5+	4	3	2	1
Powerband **3kW**, **80%** sensitive	2.916	84.31	20.58	8.45	9.46	14.55	31.27

Scenario	Mean of years of deferral	Total	Years of deferral 5+	4	3	2	1
Powerband **3kW**, **60%** sensitive	2.702	80.65	16.33	9.44	7.48	11.44	35.96
Powerband **3kW**, **40%** sensitive	2.423	69.43	10.44	5.56	9.53	10.21	33.69
Powerband **4kW**, **80%** sensitive	2.036	48.28	5.32	2.86	3.27	8.09	28.73
Powerband **4kW**, **60%** sensitive	1.943	38.93	4.29	1.30	1.81	6.81	24.72
Powerband **4kW**, **40%** sensitive	2.030	27.88	4.29	0.59	1.31	3.38	18.31
Powerband **5kW**, **80%** sensitive	1.721	16.87	1.14	0.44	1.04	1.20	13.05
Powerband **5kW**, **60%** sensitive	1.846	16.03	1.14	0.44	1.26	1.66	11.54
Powerband **5kW**, **40%** sensitive	2.071	11.88	1.14	0.44	1.04	0.96	8.31

Appendix VI Economic data

Data tables and charts related to the analysis of tariff monetary impact.

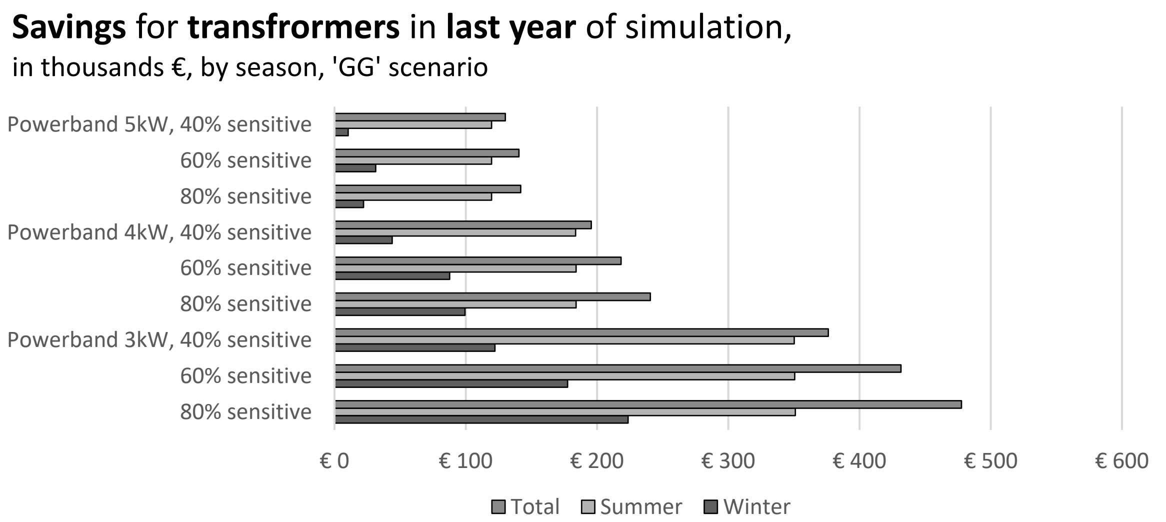

Figure VI-A Savings for transformers in last year of simulation, by season, 'GG' scenario

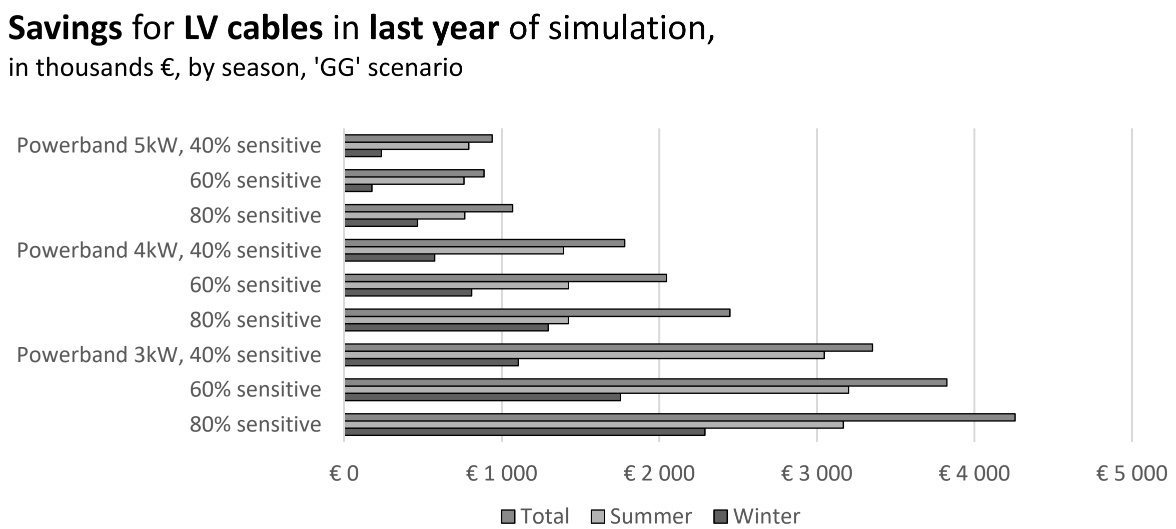

Figure VI-B Savings for LV cables in last year of simulation, by season, 'GG' scenario

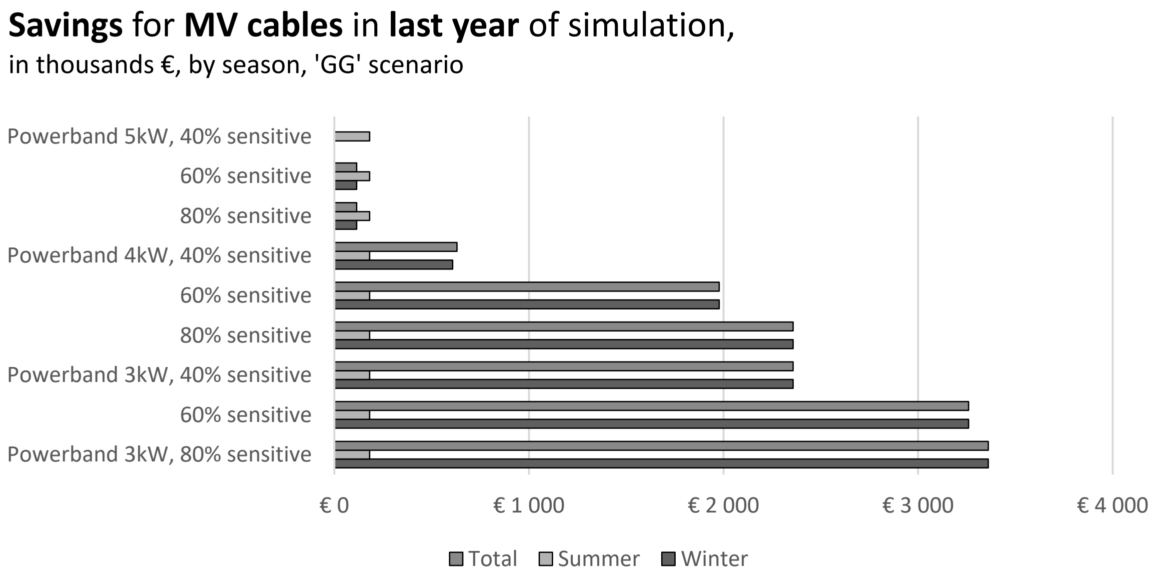

Figure VI-C Savings for MV cables in last year of simulation, by season, 'GG' scenario

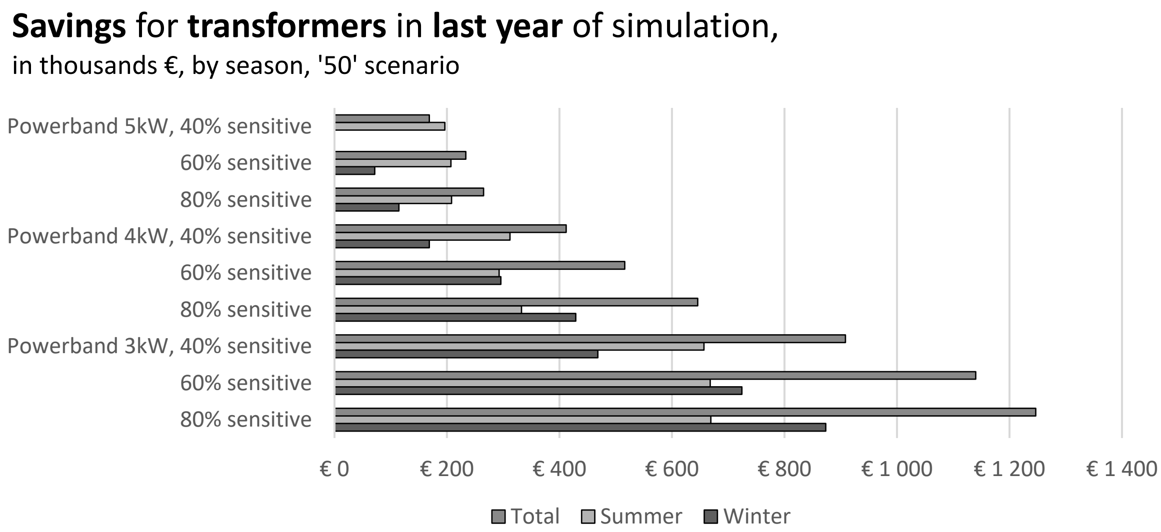

Figure VI-D Savings for transformers in last year of simulation, by season, '50' scenario

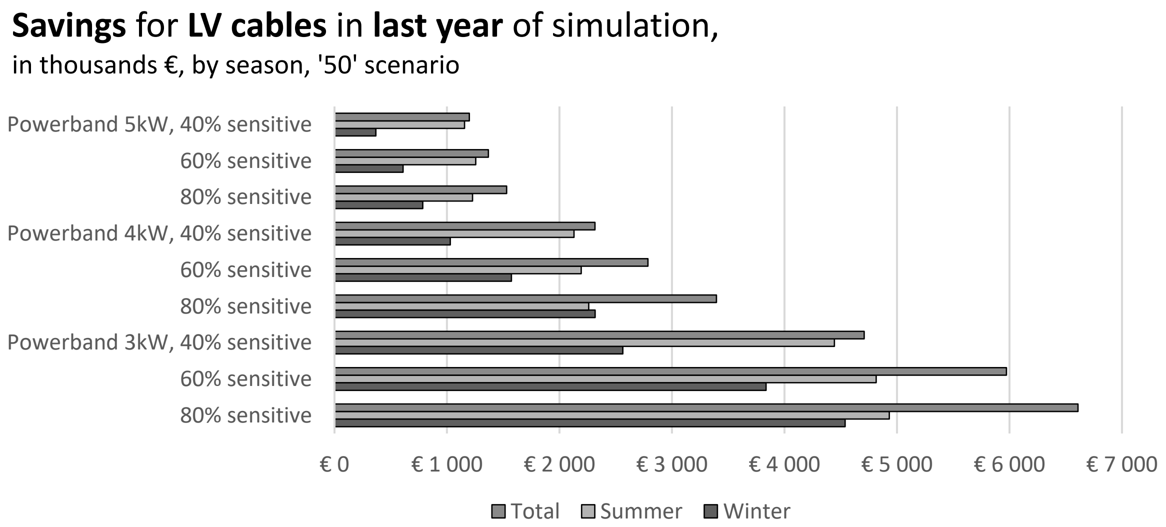

Figure VI-E Savings for LV cables in last year of simulation, by season, '50' scenario

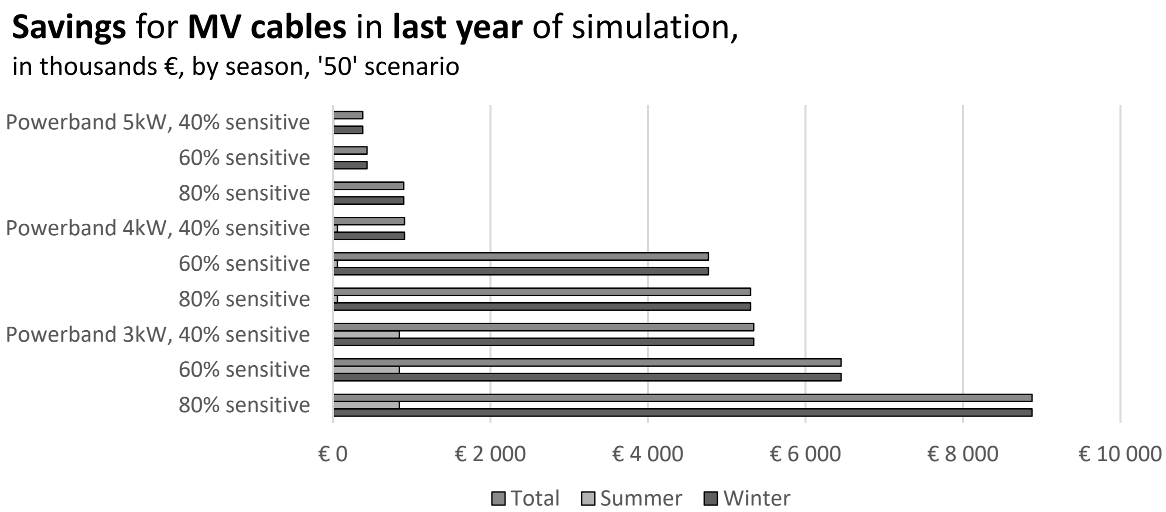

Figure VI-F Savings for MV cables in last year of simulation, by season, '50' scenario

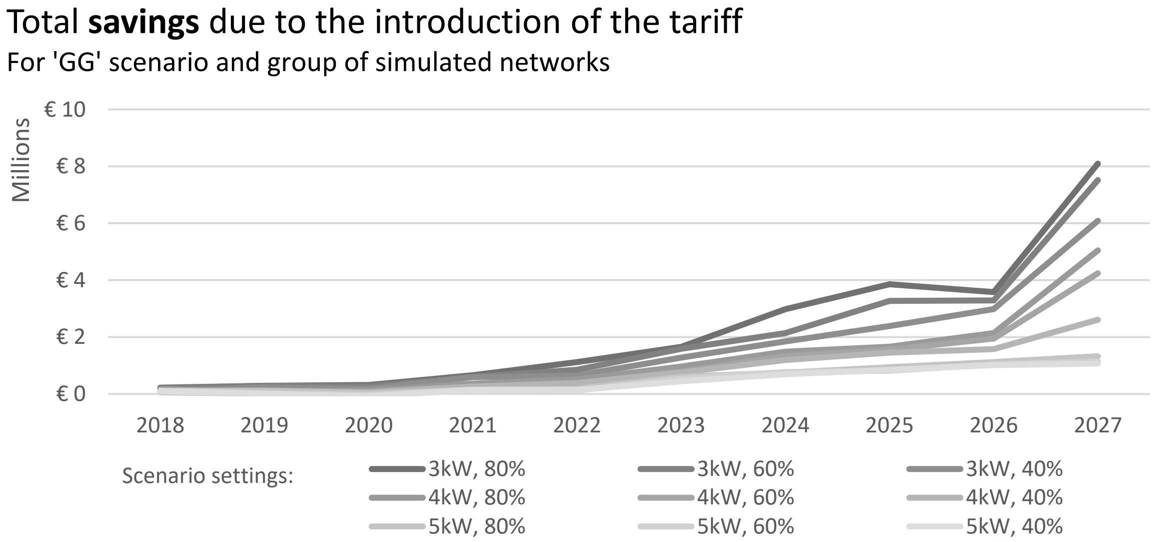

Figure VI-G Total savings due to the introduction of the tariff, 'GG' scenario

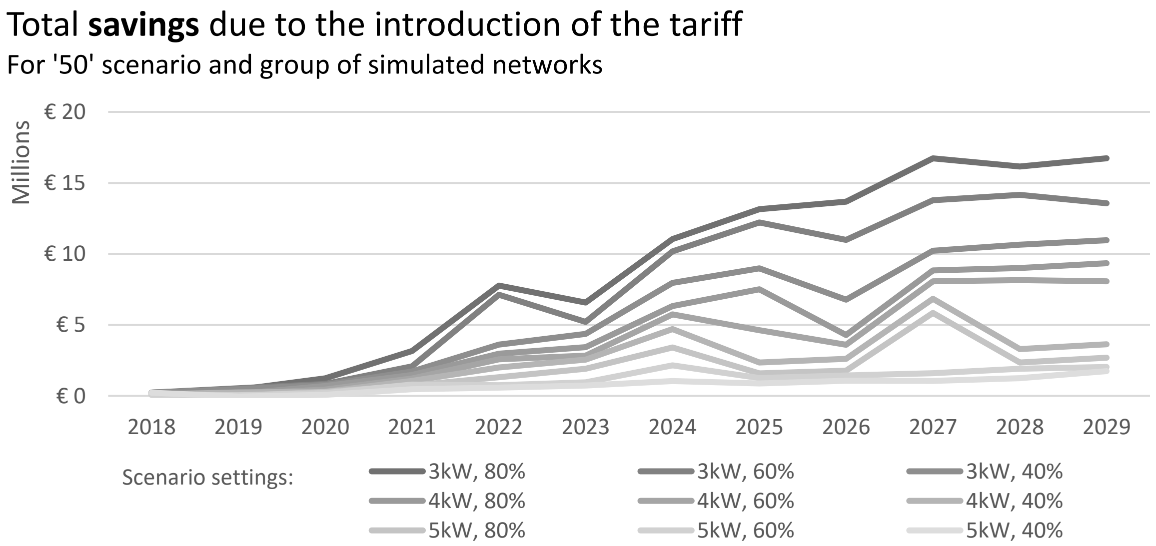

Figure VI-H Total savings due to the introduction of the tariff, '50' scenario

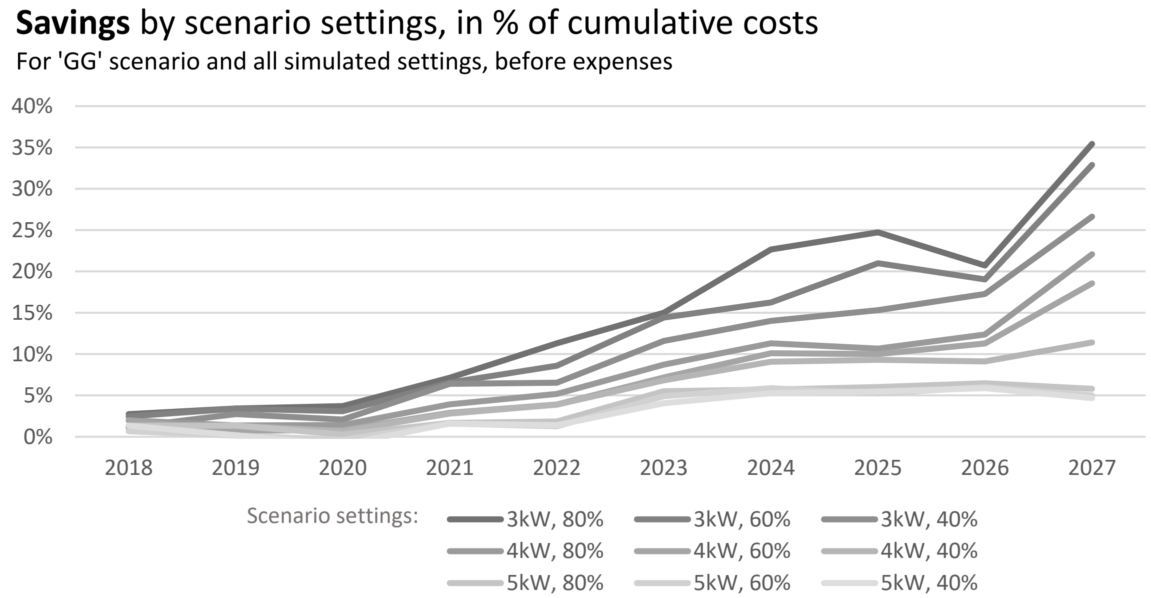

Figure VI-I Savings by scenario settings, in %, 'GG' scenario

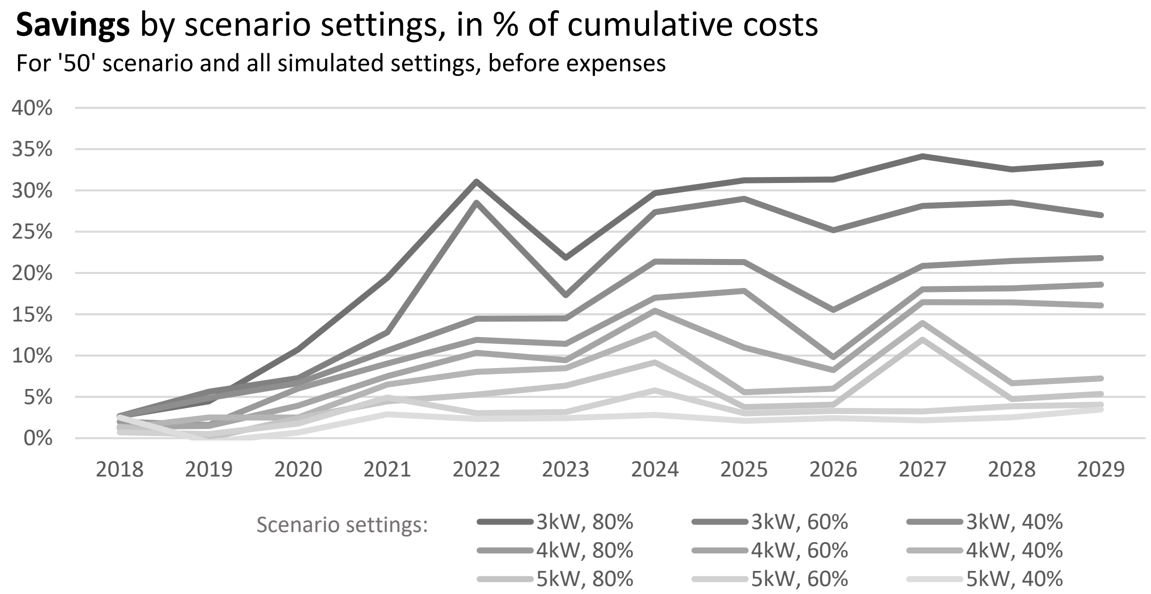

Figure VI-J Savings by scenario settings, in %, '50' scenario