Active Management
of
PV-Rich Low Voltage Networks

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Contents

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ABSTRACT

PhD Thesis: Active Management of PV-Rich Low Voltage Networks
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The increased penetration of residential-scale photovoltaic (PV) systems in European-style low voltage (LV) networks (i.e., long feeders with high number of connected customers) is leading to technical issues such as voltage rise and thermal overload of the most expensive network assets (i.e., transformer, cables). As these issues significantly limit the ability of LV networks to accommodate higher PV penetrations, Distribution Network Operators (DNOs) are required to proceed with expensive and time-consuming investments in order to reinforce or replace these assets. In contrast to this traditional approach of network reinforcement, which potentially leads to massive capital expenditure, the transition towards active LV networks where controllable elements, existing (i.e., PV systems) and likely to be adopted (i.e., battery energy storage systems, LV on-load tap changer transformers), can be managed in real-time, poses an attractive alternative.

Although several active network management schemes have been recently proposed to increase the hosting capacity of PV-rich LV networks, they are mostly based on managing voltage issues only; and, in general, aim to solve technical issues separately. Integrated solutions aiming at managing simultaneously voltage and thermal issues are required, as recent studies demonstrate that both issues can coexist in PV-rich LV networks. More importantly the majority of studies, which commonly neglect the characteristics of real LV networks (e.g., unbalanced, three-phase, radial, multiple feeders with several branches, different types of customers), use complex optimisation techniques that require expensive communication infrastructure and extensive or full network observability (currently not available in LV networks). However, considering the extensiveness of LV networks around the world, practical, cost-effective and scalable solutions that use limited and already available information are more likely to be adopted by the industry.

Considering the above gaps in the literature, this Thesis contributes by proposing innovative and scalable active network management schemes that use limited network monitoring and communication infrastructure to actively manage (1) Residential-scale PV systems, (2) Residential-scale Battery Energy Storage (BES) systems and (3) LV on-load tap changer (OLTC)-fitted transformers. The adoption of the proposed active network management schemes, which makes use of already available devices, information and requires limited monitoring (i.e., secondary distribution substation), allows making the transition towards active LV networks more practical and cost-effective.

In addition, to tackle the challenges related to this research (i.e., lack of realistic LV network modelling with high resolution time-series analyses), this Thesis, being part of the industrial project “Active Management of LV Networks” (funded by EDF R&D) and having access to French data, contributes by considering a fully modelled typical real residential French LV network (three-phase four-wire) with different characteristics and number of customers. Moreover, realistic (1-min resolution) daily time-series household (from real smart meter data) and PV generation profiles are considered while a stochastic approach (i.e., Monte Carlo) is adopted to cater for the uncertainties related to household demand as well as PV generation and location.

DECLARATION

No portion of the work referred to in this thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.

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"Let the future tell the truth, and evaluate each one according to his work and accomplishments. The present is theirs; the future, for which I have really worked, is mine"

– Nikola Tesla

DEDICATION

To Maria,

my loving wife,

who always picked me up on time and encouraged me to go on every adventure and

her love and confidence is my constant source of inspiration and encouragement.

To Tasos and Skevi,

my wonderful parents,

who have raised me to be the person I am today and

their love and support gave me strength to chase my dreams.

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Thank you all!

Chapter 1

Future Low Voltage Networks

One of the main challenges our society is facing today is the reduction of carbon emissions. As a result, during the last years, major efforts to increase environmental awareness have been made with governments all over the world and, in many cases, introducing targets to decrease emissions. The European Union (EU), for example, has set a target to source 20% of its total consumption from renewables by 2020 and 27% by 2030 [1]. To achieve these challenging targets, European countries have promoted through different incentives the adoption of residential-scale low carbon technologies (LCTs). These technologies are related to distributed generation, such as residential-scale photovoltaic (PV) systems, electro-thermal technologies, such as the electric heat pumps (EHPs), and the electrification of transport, such as the electric vehicles (EVs).

1.1 Residential-scale PV Systems

Residential-scale PV systems, in particular, became one of the most rapidly adopted LCTs in low voltage (LV) distribution networks due to the significant cost reduction of the technology itself and the incentives (e.g., feed in tariff schemes, subsidies) rolled out in several countries around the world [2].

Indeed, Figure 1-1, which shows the global annual PV additions and capacity from 2005 to 2015 [2], demonstrates that PV technology is getting more prevalent each year. Looking back a decade, the annual addition of PV capacity (i.e., 5.1GW) in 2005 increased by ten times (i.e., 50GW) in 2015 and more than half of the total capacity was installed within the last three years. Moreover, out of the total 227GW of global PV capacity, almost half (i.e., 100GW) is installed within European countries.

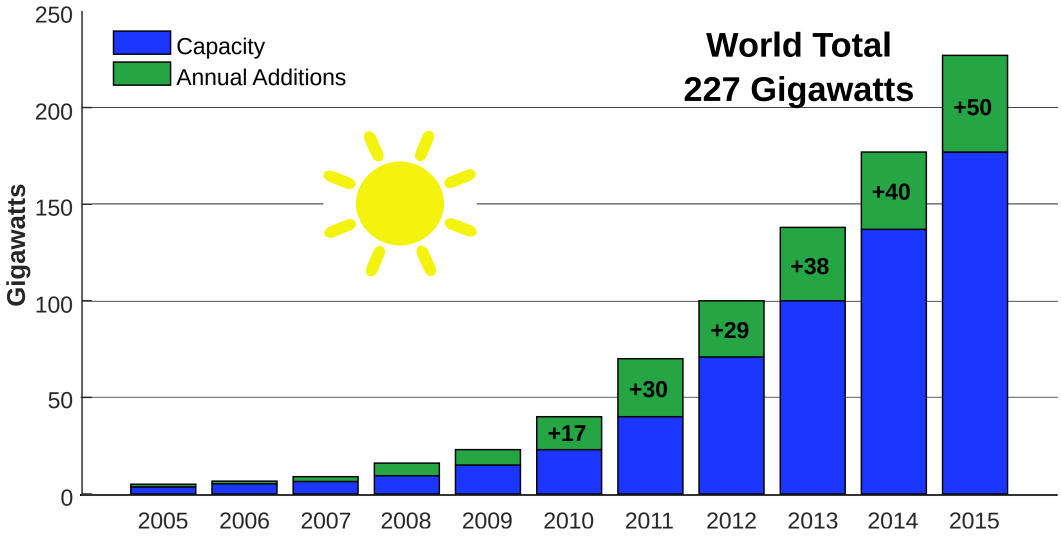


Figure 1-1 Solar PV Global Capacity and Annual Additions, 2005-2015

Germany for example, who very early introduced attractive incentives for PV system installations is leading in Europe and the world with a total of 40GW installed PV capacity by the mid of 2016 from where the 74% are considered to be residential-scale PV system installations [3, 4]. The current capacity, which corresponds to the 6.4% of total German gross power consumption [5], is expected to increase up to 52GW to achieve the government's target of having 10% of total power generation coming from PV systems by 2020.

Another example, France, which is within the top four EU countries with the highest installed PV capacity [6], has already reached 6.9GW by the mid of 2016 [7]. Out of the total PV installations in the mainland of France, the majority (91.1%) of them are installed in LV networks with sizes ranging between 3 and 9kWp. These numbers are expected to increase even more aiming to achieve the government's recently reviewed energy goals to triple the current PV installed capacity by the end of 2023 reaching 20.2GW [8].

The installation of residential-scale PV systems has also been increased in countries where there is not as much of PV potential (i.e., low sun radiation) but attractive incentives exist. For example, as a result of the UK Government's feed-in-tariff program, the total installed PV capacity in the UK reached 11GW by the end of September 2016. Interestingly, over 7GW of PV capacity was installed during the last two years which clearly demonstrates the rapid adoption of the technology [9] given the ambitious aim of the Government to double (i.e., 22GW) the capacity by 2020 [10].

Given the numerous advantages that the PV technology is offering (i.e., simple to install, non-polluting, emits no noise and requires little maintenance) [11] and the strong will of European countries to meet their renewable energy targets, the penetration levels of residential-scale PV systems in LV networks are expected to increase even more. Indeed, according to the European Photovoltaic Industry Association (EPIA), the total installed PV capacity, in Europe, is expected to increase by 50% in 2018 [12]. LV networks, however, have been traditionally designed without controllable elements (i.e., passive), assuming unidirectional power flow (i.e., from the power plant to the customer) and with no provision of PV system installations. Consequently, while penetration levels of residential-scale PV systems increase, technical issues (e.g., voltage rise, thermal overload of assets) are expected to occur; thus, limiting the network's ability to host more LCTs [13-15].

1.2 From Passive to Active LV Networks

As mentioned above and shown in Figure 1-2, LV networks have been traditionally designed and operated as passive circuits assuming a unidirectional power flow, where the power flows (i.e., blue arrows) from the Bulk Supply Point then through the transmission, distribution and finally reaching the LV customers (i.e., households) which are connected and supplied through the LV feeders (i.e., overhead or underground cables) of the corresponding LV network [16-19]. All feeders of an LV network are connected at the same point, the LV busbar, which is located at the secondary distribution substation (i.e., secondary side of the distribution transformer) and is also the final stage of the delivery of electric power.

Due to the limited observability and controllability closer to the customers (i.e., lower voltage levels), existing LV networks were designed according to the worst case loading conditions (i.e., maximum demand) without considering any kind of LCT and in particular PV systems.

Nowadays, as illustrated in Figure 1-3, with the increasing adoption of residential-scale PV systems on the consumers' side (i.e., LV networks), the traditionally assumed unidirectional power flow system is changing to a bidirectional one where

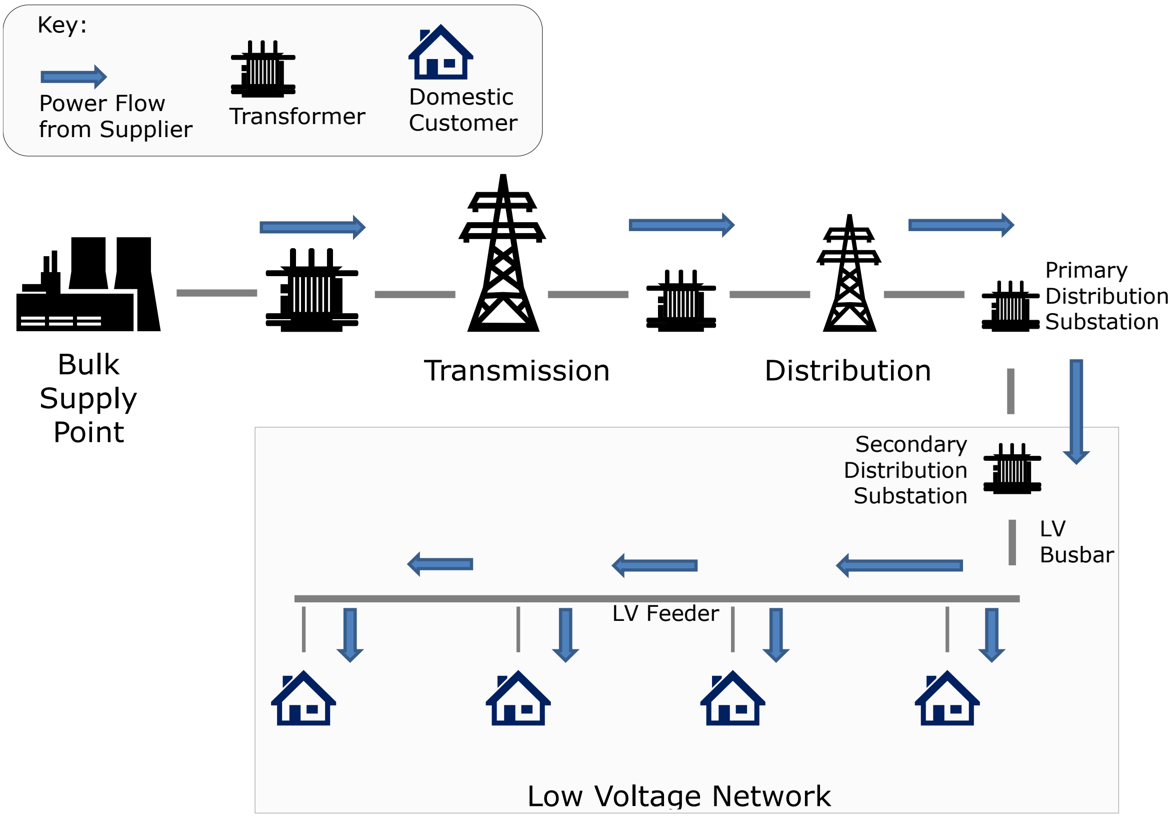


Figure 1-2 Passive LV network without LCTs

both consumers and producers interact with the LV network. However, the presence of a large number of residential-scale PV systems in LV networks, and in particular those designed considering relatively small loads (i.e., heating coming from gas and no air-conditioning systems), may result in some technical issues (i.e., voltage rise, feeder and transformer thermal overloads), particularly during periods of maximum generation and minimum demand [15, 20, 21].

1.2.1 Technical issues faced in passive LV Networks

Due to the low reactance to resistance ratio (X/R) in distribution networks, and particularly in LV (i.e., ≤ 0.5), cable resistances are high which makes them prone to voltage drops and rises when current is flowing through them. Voltage rise, for example, is considered to be one of the most dominant technical issues in LV networks [15, 22, 23] as it occurs due to the fact that residential-scale PV systems are injecting current to the network that results in significant reverse current flows (opposite direction, towards the substation). For simplicity and better understanding, considering the fundamental equation of Ohm's law, $V = I \times R$, a negative current flow will lead to a negative voltage drop meaning that the voltage will rise.

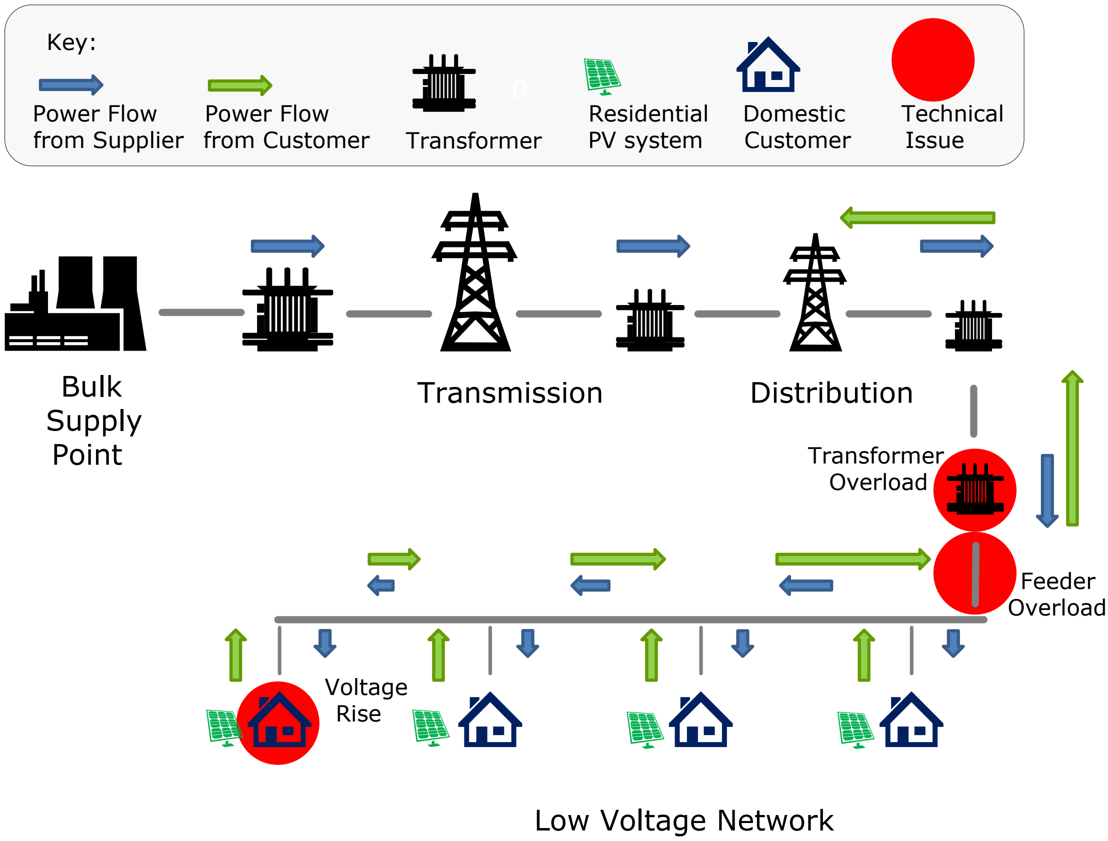


Figure 1-3 Passive LV network with residential-scale PV systems

In power systems terms, the power generated from residential-scale PV systems (green arrows) is reducing the customer's load demand which is then increasing the voltage at the PV connection point. This is also illustrated in Figure 1-3 where the demand supplied to the customers (blue arrows) is significantly lower compared to Figure 1-2. However, as the penetration of residential-scale PV systems increases in LV networks (i.e., significant current flowing in the opposite direction), voltages can rise above the statutory limit which in turn limits the hosting capacity of the network. Additionally, high voltages can significantly reduce the lifespan of most household appliances [24] while also increasing the risk of damaging sensitive electronic equipment that may be interconnected to the network (e.g., EVs, wind turbines, PV panels).

In an even worse scenario, high penetrations of local generation (i.e., residential-scale PV systems) can significantly exceed the local demand resulting to large amounts of reverse power flow (green arrows). This phenomenon, however, might result to the thermal overloading of the most important and expensive assets of the network (i.e., feeder cables and transformer) [15, 23].

To adequately cater for the aforementioned technical issues, Distribution Network Operators (DNOs) are now required to proceed with costly investments in order to reinforce the existing network assets (i.e., larger transformers and feeder cables). Hence, this passive “fit & forget” connection approach represents a barrier to the adoption of high penetrations of low carbon technologies and, in particular, residential-scale PV systems.

In contrast to the network reinforcement which will potentially lead to massive capital expenditure on the ageing network, the transition towards active LV networks where controllable elements can actively be managed, poses an attractive alternative. The vast opportunity to use monitoring data and automation to avoid unnecessary maintenance or replacement of the assets can help to increase the hosting capacity while using the existing LV network infrastructure.

1.2.2 Active LV Networks

To increase the hosting capacity of LV networks and hence enable the acceleration of the decarbonisation of the electricity distribution sector, efficient and cost-effective solutions that reduce the need of expensive and time consuming network reinforcements are required. To achieve this, DNOs are required to move from passive to active LV networks, where controllable devices and low carbon technologies are actively managed to solve technical issues such as voltage rise/drop and thermal overloads [22, 25, 26].

1.2.3 Centralised and Decentralised Control Approaches

Emerging LCTs offer numerous controllability options which can be used in either a “centralised” (i.e., transformer as the ‘hub’) or “decentralised” (local) way to manage voltage and thermal issues.

1.2.3.1 Centralised Control

Considering a “centralised” control approach, a central controller (i.e., ‘hub’ controller), located at the secondary distribution substation, can obtain data from several remote monitoring points across the LV network. Gathering all monitoring data at the ‘hub’ controller allows for a better visualisation of the LV network state

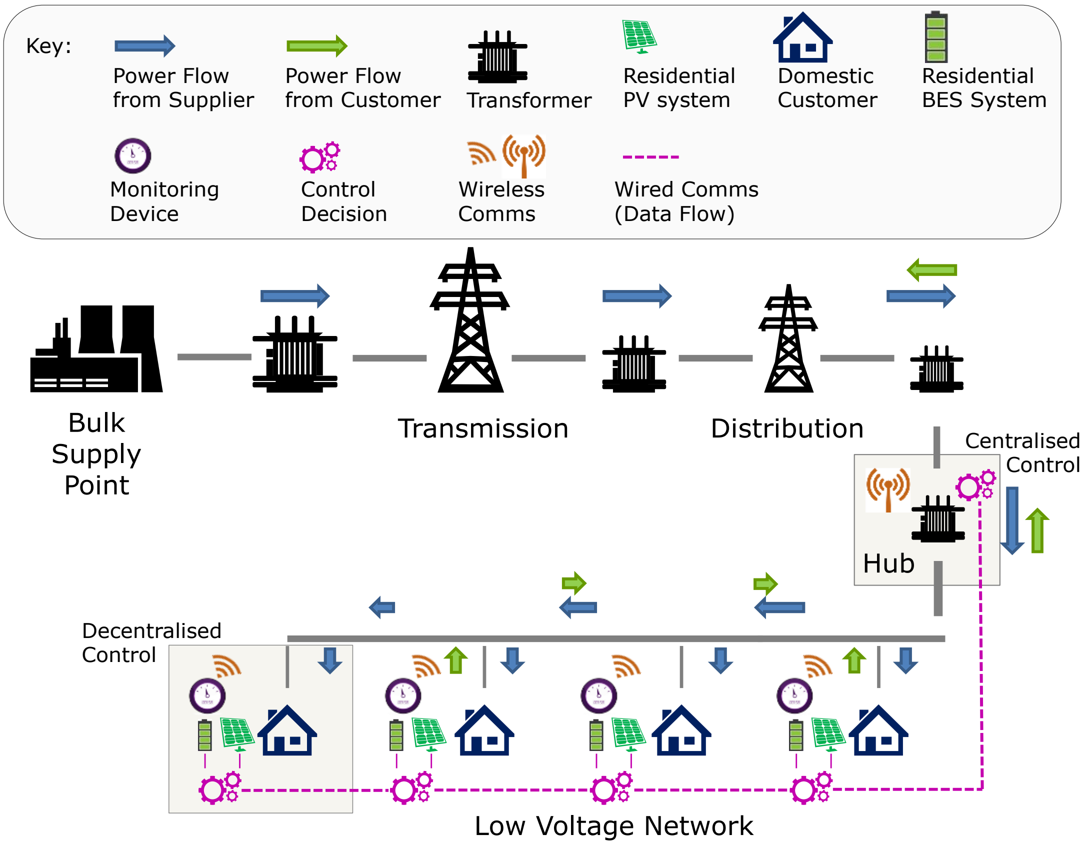


Figure 1-4 Active LV network

which then enables the provision of adequate control signals to the corresponding LCTs and control devices to manage potential voltage and/or thermal issues.

To provide an example, Figure 1-4 demonstrates a simple schematic of an active LV network where depending on the control cycle (i.e., data sampling rate), monitoring data from across the LV network can be sent through communication devices (either wireless or wired) to the "hub" controller. Once the data are received, the "hub" controller would then process it and based on a control algorithm can instruct PV systems to operate (e.g. reduce maximum generation output) in a way that improves the LV network constraints and satisfies an operational goal (e.g., thermal and voltage limits). Most studies found in the literature (discussed in section 2.3.2), due to the increased complexity (i.e., large number of PV systems with different ratings, location and behaviour of LV customers), apply complex optimisation algorithms to calculate optimal settings for the PV systems. This, however, requires extensive LV network visibility and information (i.e., network topology) which is not usually available to DNOs, making the application of such approaches difficult to implement. Thus, centralised control approaches that are scalable and practical to implement need to be developed.

Under the same control approach (i.e., centralised) the use of even more mature technologies, commonly used in higher voltage levels, can also be adopted in LV networks. Such technologies are the on-load tap changers (OLTCs) which can be adopted at secondary distribution substations (i.e., MV/LV) and actively managed to alleviate voltage issues, hence increasing the network's hosting LCT capacity and reducing the need of PV generation curtailment [27]. Although the use of LV OLTC-fitted transformers has been recently studied in order to increase the flexibility of voltage management closer to LV customers [28, 29], traditional OLTC control concepts (i.e., fixed voltage target) might not be adequate to manage voltages issues as the voltage level among different feeders (connected at the same transformer) might vary due to the particular characteristics of LV networks (i.e., uneven LCT penetration, load unbalance, etc.). Therefore, remote monitoring data closer to the LV customers and in particular critical network points (i.e., farthest customer connections) is required to visualise the state of the network thus allowing taking more accurate decisions. Moreover, considering that contrasting voltages might occur in LV networks (i.e., one feeder with high PV penetration and other heavily loaded) OLTC control methods able to satisfy both issues need to be investigated.

Despite the benefits provided by a centralised control approach, the lack of observability in LV networks requires a significant capital investment in information and communication infrastructure (ICT) that allows a two-way communication between the "hub" controller and the corresponding control and remote monitoring devices. Furthermore, the corresponding challenges associated with the increased amount of remote monitoring data should be taken into account as the cost of gathering, storing, and analysing them can be significant; making the centralised control approach a less suitable solution for DNOs.

1.2.3.2 Decentralised Control

On the other hand, adopting a "decentralised" control approach stands as another attractive alternative allowing controllable devices to operate autonomously based on their local controller that responds to local network conditions (e.g., voltage level) and requirements (e.g., statutory limits). Decentralised control approaches offer the advantage of "plug and play" as there is no need of a central controller and more importantly, as actions are taken locally, no communication infrastructure is required making the adoption of such an approach cost-effective.

Under this control approach (i.e., decentralised), modern inverters installed in residential-scale PV systems can be used as they have a fast (i.e., fraction of a second) and flexible internal control mechanism that can implement several local control functions [30] aiming to mitigate technical issues (i.e., voltage rise/drop, transformer and feeder thermal overloads), thus increasing the ability of LV networks to host more LCTs. Such decentralised control functions are the Volt-Var and Volt-Watt control of PV inverters which can adjust the reactive and active power output of the inverter based on the voltage level at the connection point of the PV system, respectively. Although the adoption of decentralised control of residential-scale PV inverters has been investigated in the literature (discussed in section 2.3.2.1), a significant number of these studies [31-35] apply complex optimisation algorithms to calculate the optimal settings for each PV inverter active and reactive power controller. Despite the need of extensive information/visibility of the network which is not commonly available, individual settings for each inverter are required, increasing the implementation challenges. Moreover, several studies [36-38] assume PV inverter ratings that can be high enough to maintain the full solar output (kWp) and the requested vars. In reality, however, residential-scale PV inverters are currently sized economically to the end user (not for network support) and therefore might have limited capability to produce or absorb the required reactive power (i.e., vars) in periods of high power output (i.e., sunny weather condition) as the available reactive power headroom is varying throughout the day (i.e., variable solar irradiance).

Consequently, the adoption of these decentralised PV control functions (i.e., Volt-Var, Volt-Watt) has to be thoroughly investigated considering the corresponding specifications or limitations (e.g., limited reactive capability) associated with the commercially available PV systems. More importantly, scalable and easy to implement solutions, such as the use of universal PV inverter settings, are required to accelerate the adoption of these decentralised control functions that will help manage technical issues.

Additional flexibility can be achieved with residential-scale battery energy storage (BES) systems which are considered to be one of the key technologies in future LV networks [39]. Recently, residential-scale BES systems (up to ~20 kWh) have been introduced by several manufacturers (e.g., Tesla, Siemens, ABB) with the primary goal of helping householders maximise the usage of PV generation by storing excess generation during the day to use later at night [39, 40]. However, BES systems have the potential –yet untapped– to mitigate impacts associated with the excess of PV generation (e.g., voltage and thermal issues), thus providing DNOs with an alternative solution to reinforcement. Although the adoption of residential-scale BES systems has been introduced only just recently, several studies try to address this issue [41-46]. However, they focus only on DNO benefits (i.e., managing voltage and thermal issues) without considering the primary goal of customers (i.e., lower grid dependency). Therefore, as BES systems are expected to be attached to residential-scale PV systems, it is important to develop control methods that can provide benefits to both customers (i.e., lower grid dependency) and DNOs (i.e., managing voltage and thermal issues).

1.2.4 Challenges

This section identifies and discusses the main challenges associated with the research on the active management of PV-rich LV networks.

1.2.4.1 Detailed Modelling and time-series Analyses

With the increasing uptake of residential-scale PV systems there is a clear need to study their impacts in LV networks while also developing suitable active network management solutions to mitigate those. To successfully perform these studies, detailed, close to reality models of LV networks are required as they allow capturing their particularities (e.g., load unbalance, cable characteristics) compared to synthetic or generic models. However, the passive nature of LV networks (i.e., neither monitored nor controlled) as well as the fact that DNOs have historically worked with synthetic (or generic) networks (to assess the requirements of the LV network planning stage) it is uncommon for the DNOs to hold accurate network data. This poses a critical challenge in realistic modelling.

Along with the above, traditionally performed (by DNOs and researchers) power flow analyses considering only snapshots of load and generation profiles pose another significant challenge when analysing LV networks as these are unable to capture the time-series behaviour of customer demand and PV generation. It is therefore important to perform realistic time-series analyses that allow not only capturing the behaviour of demand and generation but also their correlation through the day. Hence, high granularity (e.g., scale of seconds and minutes) time-series demand and generation profiles are essential to allow realistic modelling and time-series analyses.

This PhD project, however, as part of the industrial project “Active Management of LV Networks” funded by the Électricité de France (EDF) R&D (i.e., the largest R&D centre in Europe), had access to real French data (i.e., network, demand and generation) which allowed to carry out realistic studies and cover all the aforementioned challenges. Hence, this research, taking advantage of these data, uses a real typical residential, French LV network (three-phase four-wire) with different characteristics and number of customers, adopting realistic (1-min resolution) daily time-series household (from real smart meter data) and PV profiles.

1.2.4.2 Behavioural and Locational Uncertainties

The rapid adoption of residential-scale LCTs and particularly PV systems, in future LV distribution networks raises significant challenges due to their behavioural and locational uncertainties [15]. Consequently, commonly adopted deterministic analyses or specific scenarios (i.e., worst case) are not suitable considering the intermittent behaviour of load and PV generation. Hence, to cope with the corresponding uncertainties and to truly understand the impacts on the electricity infrastructure to which the PV systems will connect to, as well as potential solutions, stochastic approaches must be adopted.

To tackle this challenge and cater for the uncertainties related to household demand as well as PV generation and location, this PhD Thesis adopts a stochastic approach (i.e., Monte Carlo methodology). This allows extracting more meaningful results as well as understanding the extent to which an investigated active network management control method can cope under different network scenarios.

1.2.4.3 Network Observability

To effectively manage LV networks, extended visibility is required. This will enable DNOs to better understand the state of the networks and therefore utilise their assets more efficiently in real time. Unfortunately, LV networks as of today (i.e., passive), are not equipped with monitoring or communication devices [47], thus making the adoption of active management techniques even more challenging. Although the already planned and on-going installation of advanced metering infrastructure (AMI) technologies (i.e., smart meters) in many European countries [48] might cover this gap of observability in LV networks, it is expected to take several years more to be fully implemented, hence allowing DNOs to use measurement data in real-time. Furthermore, it is uncertain whether AMI data can actually be used for operational purposes as this depends on how and who manages all these data. Thus interim solutions are required to enable the adoption of active management techniques in LV networks.

For the above reason, in the last few years, several DNOs have shown an interest in increasing the network visibility closer to the customers by installing remote monitoring devices at critical points (i.e., feeders' end points) within their LV networks [47, 49]. The use of remote monitoring devices and the corresponding communication infrastructure, although ensuring accurate visibility of the LV network, results in higher capital and operational costs. Therefore, considering the extensiveness of LV networks around the world (e.g., circa 500,000 in the UK), the installation of monitoring devices might not be economically feasible [50, 51].

Consequently, it is essential to explore the extent to which limited observability with existing (or installed) secondary substation monitoring (i.e., LV busbar) could be used to augment the network visibility, particularly at critical points of the LV network. Considering the above, this PhD Thesis aims to provide practical and scalable solutions to actively manage PV-rich LV networks using limited observability (e.g., LV busbar, critical points) and available network information.

1.3 Active Management of LV Networks Project

The work presented in this Thesis has been sponsored by the industrial project "Active Management of LV Networks". This was a three and half year project funded by the Électricité de France R&D (i.e., the largest R&D centre in Europe) and run by The University of Manchester under the Industrial Cooperative Awards in Science & Technology (iCASE) fund. The aim of this project was to investigate the effect of applying active management techniques to increase the ability of LV networks to accommodate higher number of LCTs, in particular, residential-scale PV systems and EVs. The project was divided into three main tasks: (1) the coordinated control of residential-scale LCTs (i.e., PV systems, EVs), (2) the control of residential-scale BES systems and (3) the utilisation of LV OLTC-fitted transformers to control voltages and congestion in LV networks. More importantly, the project provided the unique opportunity to access real French LV data (i.e., network, demand and PV generation) that allowed carrying detailed realistic studies.

1.4 Aims and Objectives

The adoption of LCTs in LV networks can help achieve the targets set by many countries to reduce the carbon emissions. Despite the benefits gained, the continuously increasing penetration of LCTs, and, in particular, PV systems, can also result in technical issues (i.e., voltage rise, thermal overloads), hence limiting the number of LCTs that can be connected. In this context, and consistent with the objective of the Active Management of LV Networks (but not limited to it), the main purpose of this Thesis is to provide innovative, practical and scalable solutions to actively manage PV-rich LV networks in order to increase their hosting capacity. Thus, to achieve the main purpose stated above, the following objectives have been established:

1. The use of realistic models of LV networks from real data (GIS) to perform the analyses.

2. The creation of realistic daily high resolution load (based on real smart meter data) and PV generation profiles in order to carry out time-series analyses.

3. The investigation, development and implementation of scalable solutions to actively manage residential-scale PV systems (in either a decentralised or centralised way) in order to solve technical issues in LV networks.

4. The investigation, development and implementation of scalable solution to actively manage residential-scale BES systems (installed along with PV systems) in order to solve technical issues in LV networks.

5. The utilisation of OLTC-fitted LV transformers to manage voltage issues in LV networks considering both local monitoring (at the busbar) and remote monitoring points (e.g., end nodes).

1.5 Main Contributions of the Thesis

This section summarises the main and original contributions of this Thesis.

1.5.1 Management of Residential-scale PV Systems

Decentralised Voltage Control (Volt-Watt). It is demonstrated that a universal, single set of Volt-Watt settings is possible to be identified with the proposed method as the most adequate to effectively manage voltage issues, regardless the penetration, in a given LV network. This brings benefits to the DNO as it increases the scalability of the corresponding control method due to the fact that these settings are universal for all PV inverters, require a one-off setup (e.g., on the installation day) and are valid for any PV penetration.

Decentralised Voltage Control (Volt-Var). The limitations and drawbacks of adopting such a control method, with commercially available residential-scale PV inverters, are demonstrated for the first time. Findings show that the benefits of this control approach are minimal due to the limited reactive capability of PV inverters at peak generation periods, where voltages are higher. This allows DNOs to take more informed decisions when adopting decentralised voltage control with reactive compensation (i.e., Volt-Var).

Centralised Thermal Controller. An innovative and scalable centralised control logic which bridges the gaps in the literature (e.g., adoption of complex optimisation techniques, requirement of extensive network monitoring, not scalable, etc.) is developed and proposed in this Thesis. The proposed control logic aims to manage thermal overloads in PV-rich LV networks (for any penetration) while using limited network observability (i.e., substation measurements only). The proposed control logic, with its performance successfully assessed considering different PV penetration levels (i.e., 0-100%), offers significant benefits to DNOs as it does not require the installation of remote monitoring points and reduces the need of costly communication infrastructure. More importantly, its generic nature allows it to be deployed and work on any PV-rich LV network its performance is expected to be the same as the proposed method and will always curtail the amount of energy required to keep the utilisation of assets within limits. It should also be highlighted that although the proposed control method is designed considering residential-scale PV systems as the controlled technology, it can easily be adapted to manage any other technology that can support active power control.

Combined Centralised Thermal and Decentralised Voltage Control. To provide a complete active network management aiming to solve both thermal and voltage issues at any PV penetration level, this Thesis proposes the combination of the centralised thermal controller with the decentralised voltage control (i.e., Volt-Watt). Unlike other solutions that are not easily implementable (due to complex optimisation algorithms, increased network visibility, expensive communication infrastructure), the proposed control method offers a more cost-effective solution requiring limited network observability. As previously mentioned, the generic nature of the proposed method, allows it to be deployed and work on any PV-rich LV network.

1.5.2 Management of Residential-scale Battery Energy Storage Systems

For the first time, an advanced operation mode that provides benefits both to the customer (i.e., increased self-consumption) and the DNO (i.e., voltage and thermal management) is proposed for residential-scale BES systems. The proposed operation mode, which can be programmed on residential-scale BES systems, offers the advantages of the decentralised control approach thus requiring no communication infrastructure. Based on local measurements (i.e., inverter connection point) the advanced operation mode can progressively charge/discharge the BES system in a way that increases the customer’s self-consumption while effectively eliminating all voltage issues up to high PV penetration levels beyond which it can significantly reduce them. The decentralised and generic nature of the proposed operation mode makes it replicable on any PV-rich LV network; however, it should be noted that the overall performance might be influenced by the size of the installed BES systems. For instance, although smaller sizes of BES systems will still bring benefit to the customers (i.e., reduced energy bills) they might not bring enough benefits to the DNO (i.e., voltage and thermal management) due to their limited storage capability.

1.5.3 Management of OLTC-fitted LV Transformers

A scalable and adaptive OLTC logic that aims to manage contrasting issues of voltage rise (due to the presence of generation) and drop (due to loads) is proposed in this research. Compared to traditional OLTC control approaches (i.e., fixed voltage target) that do not consider the diversified voltage levels among different feeders (due to uneven penetration of LCTs, load unbalance, etc.), the proposed method allows the automatic update of the voltage target (at the busbar) according to network conditions while using limited network observability coming from critical remote monitoring points (i.e., feeders' end points). Crucially, this provides the significant benefit of easily adapting to network changes (i.e., additional installation of PV systems or loads) without the need of reconfiguring OLTC settings. Considering the case study, the proposed OLTC control logic, which was assessed considering different PV penetrations, was found to effectively eliminate all voltage issues up to high PV penetration levels beyond which it can significantly reduce them.

1.5.4 List of Publications

The development and application of the proposed active management solutions in different analyses and studies have led to the publication of the following journal paper, conference papers and technical reports.

1.5.4.1 Journal Papers

1. **A. T. Procopiou** and L. F. Ochoa, "Voltage Control in PV-Rich LV Networks without Remote Monitoring," *IEEE Transactions on Power Systems*, vol. 32, no. 2, pp. 1224-1236, March 2017. [51]
   DOI Link: https://doi.org/10.1109/TPWRS.2016.2591063

2. **A. T. Procopiou**, J. Quiros-Tortos, and L. Ochoa, "HPC-Based Probabilistic Analysis of LV Networks with EVs: Impacts and Control," *IEEE Transactions on Smart Grid*, vol. 8, no. 3, pp. 1479-1487, May 2017. [52]
   DOI Link: https://doi.org/10.1109/TSG.2016.2604245

1.5.4.2 Conference Papers

1. **A. T. Procopiou**, C. Long, and L. F. Ochoa, "On the effects of monitoring and control settings on voltage control in PV-rich LV networks," in *Power & Energy Society General Meeting*, 2015 IEEE, 2015, pp. 1-5. [53]
   DOI Link: http://dx.doi.org/10.1109/PESGM.2015.7285791

2. L. Chao, **A. T. Procopiou**, L. F. Ochoa, G. Bryson, and D. Randles, "Performance of OLTC-based control strategies for LV networks with photovoltaics," in *Power & Energy Society General Meeting*, 2015 IEEE, 2015, pp. 1-5. [54]
   DOI Link: http://dx.doi.org/10.1109/PESGM.2015.7285618

3. **A. T. Procopiou**, L. Chao, and L. F. Ochoa, "Voltage control in LV networks: An initial investigation," in *Innovative Smart Grid Technologies Conference Europe (ISGT-Europe)*, 2014 IEEE PES, 2014, pp. 1-6. [55]
   DOI Link: http://dx.doi.org/10.1109/ISGTEurope.2014.7028971

1.5.4.3 Technical Reports

All technical reports were produced for the industrial iCASE project "Active Management of LV Networks" and submitted to the Electricite de France (EDF) R&D, who will use to make more informed decisions in terms of the solutions that could be implemented to increase the penetration of LCTs in LV network. The following reports are under a non-disclosure agreement (NDA) between the authors (Andreas T. Procopiou, Luis F. Ochoa) and the company (EDF R&D).

1. **A. T. Procopiou** and L. F. Ochoa, Deliverable 2.4 "Benefits of adopting Storage Devices in LV networks", Active Management of LV Networks, prepared for EDF R&D, October 2016 [56]

2. **A. T. Procopiou** and L. F. Ochoa, Deliverable 2.3 "Benefits of controlling EVs and PV in combination with other technologies", Active Management of LV Networks, prepared for EDF R&D, June 2016 [57]

3. **A. T. Procopiou** and L. F. Ochoa, Deliverable 2.2 "Benefits of controlling EVs and PV", Active Management of LV Networks, prepared for EDF R&D, October 2016 [58]

4. **A. T. Procopiou** and L. F. Ochoa, Deliverable 2.1 "EVs and PV: Literature review and initial modelling", Active Management of LV Networks, prepared for EDF R&D, April 2015 [59]

5. **A. T. Procopiou** and L. F. Ochoa, Deliverable 1.3 "Monitoring Aspects and Benefits of OLTC in LV Networks", Active Management of LV Networks, prepared for EDF R&D, April 2015 [59]

6. **A. T. Procopiou** and L. F. Ochoa, Deliverable 1.2 "Benefits of OLTC transformers in LV", Active Management of LV Networks, prepared for EDF R&D, November 2014 [60]

7. **A. T. Procopiou** and L. F. Ochoa, Deliverable 1.1 "Literature review and initial modelling", Active Management of LV Networks, prepared for EDF R&D, May 2014 [61]

1.6 Thesis Outline

This Thesis consists of eight chapters in total. The remaining seven chapters that follow are outlined below.

<u>Chapter 2 - Managing Impacts and State of the Art</u>

Chapter 2 presents the research that has been carried out in the literature considering active network management schemes aiming to solve voltage and thermal issues in LV networks due to high penetrations of residential-scale PV systems. This includes decentralised and centralised control of residential-scale PV systems, BES systems and the use of LV OLTC-fitted transformers. The gaps of the current research in the literature, which are addressed by this Thesis, are outlined and discussed.

<u>Chapter 3 - Control Schemes for PV-Rich LV Networks</u>

This chapter provides the details of all the control schemes proposed in this Thesis aiming at managing voltage and/or thermal issues in PV-rich LV networks. First, section 3.2, details the control schemes proposed to actively manage residential-scale PV systems aiming at managing both voltage and thermal issues. An “advanced operation” mode for residential-scale battery energy storage systems is proposed and presented in section 3.3 to bring benefits to both customers (i.e., increased self-consumption) and DNO (i.e., voltage and thermal management). Lastly, the proposed control logic for LV OLTC-fitted transformers aiming at managing contrasting voltages issues (rise and drop) using limited network observability coming from critical remote monitoring points (i.e., farthest customer connections or feeders' end points) is proposed and presented in section 3.4.

Chapter 4 – Case Study Part 1: Modelling

Taking advantage of having access to real French data (due to this research being part of an industrial project), this chapter, presents the modelling of different elements essential to perform realistic time-series analyses and assess the performance of the proposed active network management schemes. First, the details (i.e., number of feeders, connected customers and transformer) and topology of the real residential French LV network used in this research are presented. Then, the modelling aspects of the French domestic load profiles (based on real smart meter data) and PV generation profiles are presented along with load and generation profile allocation procedures adopted in this work. Finally, the Monte Carlo methodology and performance metrics, used in this Thesis to assess the performance of the proposed control schemes, are presented.

Chapter 5 – Case Study Part 2: Simulation Analyses for Residential-scale PV Systems

This chapter presents the simulation analyses carried on the real French LV network to assess the performance of the proposed control schemes for residential-scale PV systems under different PV penetration levels during summer (i.e., worst case scenario - low demand with high generation). First, a stochastic analysis is performed to assess the performance of the most common decentralised voltage control approaches (i.e., Volt-Var and Volt-Watt). Thereafter, the performance of the proposed centralised thermal control is investigated, along with the performance of the proposed combined centralised thermal and decentralised voltage control. Finally, a summary of the most important findings is presented.

Chapter 6 – Case Study Part 3: Simulation Analyses for Residential-scale BES Systems

The proposed "advanced operation" mode for residential-scale BES systems is adopted in this chapter on the real French LV network to assess its performance under different PV penetration levels during summer. Its performance is compared against the "normal operation" mode adopted based on available specifications from BES system manufacturer. A time-series analysis is first performed on the two BES operation modes. Then, their performances are assessed adopting a stochastic analysis considering different PV penetration levels. Finally, a summary of the most important findings is presented.

Chapter 7 – Case Study Part 4: Simulation Analyses for LV OLTC-fitted Transformers

This chapter investigates and presents a quantitative assessment of the benefits when adopting OLTC-fitted transformers with the proposed control logic in order to manage voltage issues in PV-rich LV networks. First the OLTC-fitted transformer adopted for the corresponding analyses is presented. Then, the time-series performance of the proposed OLTC control logic is assessed using the real French LV network. Lastly, its performance is stochastically investigated considering different penetration levels of residential-scale PV systems for different days in summer, levels of monitoring and control cycles. Moreover, this chapter summarises and compares the technical benefits (i.e., voltage and thermal management) of the proposed control schemes investigated in this Thesis, along with different implementation aspects (i.e., potential required investments, effects on customers).

Chapter 8 – Conclusions and Future Work

This chapter presents a summary of the main findings and conclusions gained from this research as well as potential improvements and future work that can follow the work presented in this Thesis.

Chapter 2

Managing Impacts and State of the Art

2.1 Introduction

This chapter presents the research that has been carried out in the literature considering active network management schemes aiming to solve voltage and thermal issues in LV networks due to high penetration of residential-scale PV systems. The gaps of the available research in the literature, which are addressed by this Thesis, are outlined and discussed.

2.2 Impacts of PV Systems on Passive LV Networks

Given the rapid adoption of residential-scale PV systems in passive LV networks (designed with relatively small considering relatively small loads, and without any provision for accommodating any kind of LCT), it is essential to investigate and understand the potential technical impacts that these might cause to the networks. A complete description of the possible technical impacts occurring from PV systems integration in distribution networks is presented in [62] highlighting the following: voltage rise, voltage fluctuations, voltage and current unbalance, reverse power flow, asset overloading, increased power losses and increased total harmonic distortion.

In order to improve the understanding of the technical impacts associated with the integration of residential-scale PV systems in LV networks, several authors have carried out diverse studies [23, 63-65]. One of the most interesting studies performed in [63, 64], assesses the impacts of different PV penetrations on two real UK LV networks in order to estimate their corresponding hosting capabilities applying a Monte Carlo technique. The analysis, which considers 5-min resolution synthetic data for domestic load and PV generation, highlighted the impacts of voltage rise, reverse power flow, and the overloading of feeder segments which are results of high PV penetration levels. Considering an even more thorough impact study, which was performed on more than 10,000 real LV networks in New Zealand and using real domestic load and generation profiles, the authors in [23] highlight among different technical impacts (e.g., reverse power flow, voltage unbalance), that voltage rise is one of the most dominant in LV networks.

According to the aforementioned studies it is obvious that high penetrations of residential-scale PV systems in passive LV networks, and particularly those designed considering relatively small loads, will lead to technical issues such as voltage rise and thermal overloads of assets (due to reverse power flow). To illustrate how these issues occur and how they might affect passive LV networks, Figure 2-1 presents a simplified LV network.

For simplicity, the LV network in Figure 2-1 supplies only one household with a demand of P_L and Q_L through a feeder with an impedance of $R + jX$. At the same connection point, a PV system is also connected with an active and reactive power equal to P_{PV} and Q_{PV}, respectively.

First, assuming that no PV system is present, the voltage at the household connection point, bus 1 (V_1), can be approximated (in per unit) using (2.1). This is illustrated in Figure 2-1 (grey line), where V is the voltage at the substation busbar.

$$V_1 \approx V - (R \cdot P_L) - j(X \cdot Q_L) \tag{2.1}$$

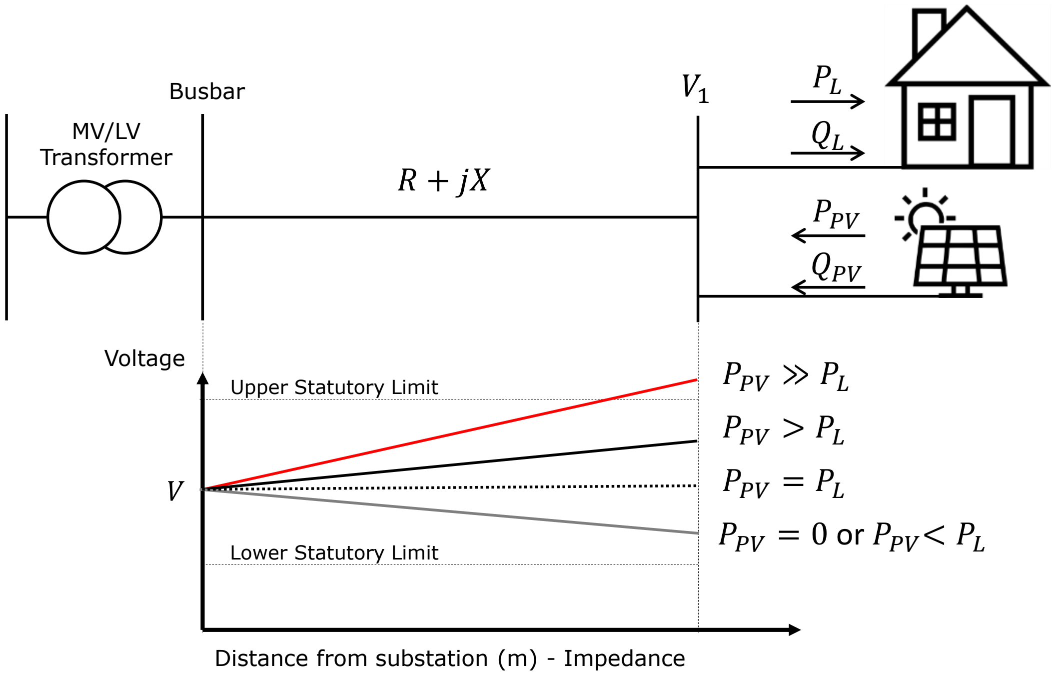


Figure 2-1 Voltage rise and drop on a passive network

As shown in the figure, under load-only conditions ($P_{PV} = 0$), the voltage at the customer's connection point is dropping as it is directly influenced by its demand (i.e., P_L,Q_L) and the impedance (i.e., $R + jX$) between its connection point and the substation. It should be noted that the reactance to resistance ratio (X/R) in distribution networks, and particularly in LV, is considerably lower (≤ 0.5) than in higher voltage level networks (≥ 10) and therefore the values of cable resistances are high, leading to significant voltage drops or rises along the line [66].

However, once the PV system is connected, the voltage at the household connection point (V_1), which can now be approximately calculated using (2.2) as in [67], is likely to increase due to the reverse power flowing back to the substation.

$$V_1 \approx V + R(P_{PV} - P_L) + X(Q_{PV} - Q_L) \tag{2.2}$$

As indicated in (2.2) and observed in Figure 2-1, voltage will increase depending on the level of PV generation. For example, assuming a unity power factor for both demand and generation (i.e., $Q_L = Q_{PV} = 0$), if the PV generation is equal to the customer's demand (i.e., $P_{PV} = P_L$), then voltage is neither expected to drop nor rise as no power is demanded or generated at the customer's connection point (i.e., no power is flowing). However, as soon as the PV generation exceeds the local demand (i.e., $P_{PV} > P_L$), power starts to flow towards the substation which results in the voltage rise at the customer's connection point (see Figure 2-1). With significantly higher PV generation (i.e., $P_{PV} \gg P_L$), this issue becomes even more severe as voltage can rise above the statutory limits (red line, Figure 2-1) due to the excessive power flowing back to the substation.

Furthermore, as previously discussed in section 1.2.1, this excessive amount of reverse power flow (due to high PV generation) might result in the thermal overloading of the most important and expensive assets of the network (i.e., feeder cables and transformer). Overloading the corresponding assets above their maximum current capacity leads to the increment of their insulation temperature above their operational limit. Consequently, this phenomenon may result in damaging or accelerating the ageing of the assets.

Considering this passive nature (i.e., no controllable elements) of traditional LV networks, DNOs are now facing significant challenges as the connection of large numbers of PV systems might lead to technical impacts (i.e., voltage rise and asset thermal overloading), that unfortunately limit the hosting capacity of LV networks [68]. Although the traditional solution of reinforcing (or replacing) the existing network assets (i.e., larger transformers and feeder cables) allows accommodating higher number of PV systems, it requires significant capital investments [29, 69]. Therefore, this passive “fit & forget” connection approach represents a barrier to the adoption of high penetrations of low carbon technologies and, in particular, residential-scale PV systems.

An alternative to this costly network reinforcement, is the active management of the PV systems themselves and the use of other technologies (i.e., energy storage, OLTC) to solve (or postpone) these technical impacts [29]. The following sections present the most prominent research carried out in the literature aiming at managing voltage and thermal issues by controlling residential-scale PV systems, BES systems and LV OLTC-fitted transformers.

2.3 Residential-scale PV systems

Modern inverters for residential-scale PV systems are considered to be intelligent as they have far more capabilities than just converting DC to AC power. Today, commercially available inverters provide power control functions which are able to limit the active power output (i.e., curtailment) of the corresponding PV system that they are connected to and also inject or absorb reactive power [30, 70, 71]. What is more important, they are equipped with numerous two-way communication interfaces enabling them to be remotely controlled through wired (e.g., power line carrier, fibre optic, dedicated lines) or wireless (e.g., radio/cellular signals, WiFi, WiMAX, ZigBee) connections. Although standards in Europe, as stated in [72], have allowed reactive power compensation from small scale distributed generators (i.e., residential-scale PV systems) to manage voltage, PV inverters are still operated only to convert DC to AC power; thus their real potential is yet untapped.

2.3.1 Embedded Active and Reactive Power Control Functions

To understand how PV inverters can help in actively managing LV networks, this section presents the most common power control functions which are found in modern residential-scale PV systems in Europe (e.g., France, UK) [73]. It should be noted that although a power factor control function, $\cos\varphi\,(P)$, is also embedded in modern residential-scale PV systems, only functions with a direct relation to voltage are considered in this Thesis.

2.3.1.1 Active Power Limit

This function limits the inverter's maximum output power by setting a limit as a percentage value (e.g., 50%) to which the maximum rated output power will be limited to. For example, if a PV system with a rated power of 3kWp has an active power limit of 50%, then it will be able to output only up to 1.5kW of power as illustrated in Figure 2-2. This essentially means that any resulting power above 1.5kW is curtailed.

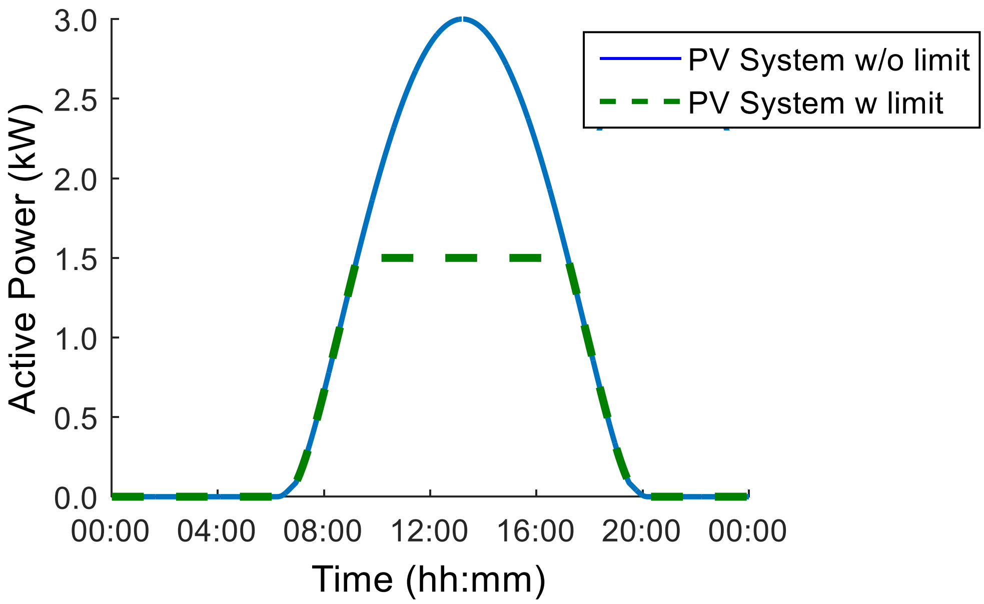


Figure 2-2 Active Power Limit function

Such function can be used in either centralised or decentralised control approaches to limit the maximum output of large number of PV systems aiming to prevent the overloading of assets (i.e., transformer and feeder cables). This, in turn, results, as a natural effect of reducing the active power, in the reduction of high voltages during peak generation.

2.3.1.2 Volt-Watt

Another control function that manages the active power output of the PV systems is the Volt-Watt which tries to maintain the voltage at the terminal of the PV system within predefined voltage limits (e.g., statutory voltage limits). It essentially limits the maximum generation capability of each individual PV system according to 1) the voltage at the point of connection (at the terminals of the PV system), and 2) the predefined Volt-Watt set-points (set either by the DNO or the owner itself). This is illustrated in Figure 2-3. Although the Volt-Watt set-points can be constructed considering multiple points to represent a detailed and accurate curve, modern residential PV inverters usually support up to 6 points to represent a linear curve (more details in section 3.2.1). While this allows PV inverters having a smaller processing unit (i.e., cheaper and smaller), it also increases scalability and practicality as less effort is required to design and setup the corresponding curves.

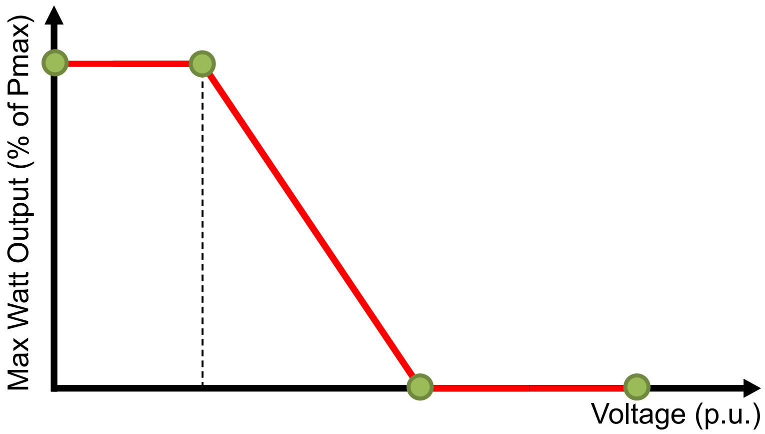


Figure 2-3 Generic Volt-Watt curve

Considering situations where high PV output and low demand might result in high feeder voltages, the Volt-Watt control function can be used to limit the maximum active power output of the PV systems and, therefore, bring voltages within the statutory limits. This control can also be beneficial in situations where existing controls (e.g., voltage control through OLTC-fitted transformer) are not able to prevent the occurrence of these high voltages. Moreover, this control function can be used to also manage thermal issues (provided that the overvoltages and the thermal overloads occur at the same time) by adopting conservative Volt-Watt set-points while managing voltages.

2.3.1.3 Volt-Var

The Volt-Var control function, similar to the Volt-Watt, tries to maintain the voltage at the terminal of a PV system within predefined voltage limits (e.g., statutory voltage limits). It essentially allows each individual PV system to provide a unique var response according to 1) the voltage at the point of connection (the terminals of the PV system), 2) the available reactive power capacity of the inverter at that point in time, and 3) the predefined Volt-Var set-points (set either by the DNO or the owner itself) as illustrated in Figure 2-4.

Such control function can be applied in a control approach where reactive power is absorbed if the local voltage begins to exceed the pre-determined upper level (as defined by the Volt-Var set-points). On the contrary, if the voltage begins to fall below the pre-determined lower level (e.g., due to the reduction in active power output) reactive power can be injected in the network to help boost the voltage back to normal levels.

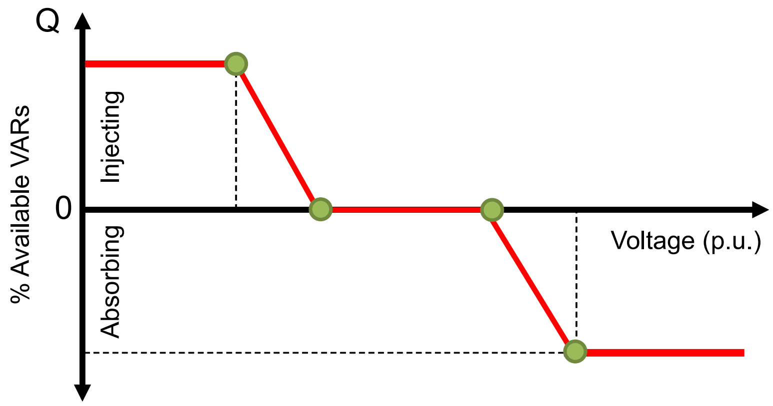


Figure 2-4 Generic Volt-Var Curve

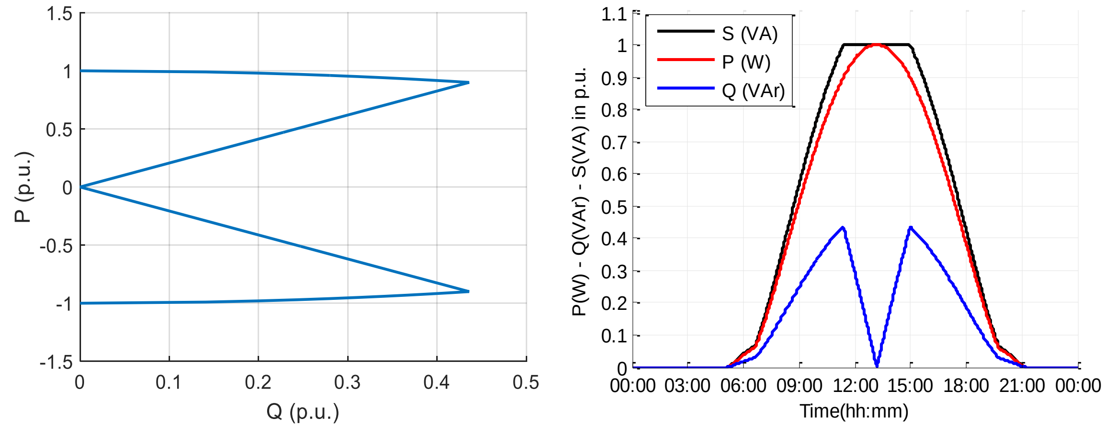
2.3.1.4 Reactive power capability of normal residential-scale inverters

It is important, however, to highlight that the Volt-Var control function depends on the reactive capability of the corresponding PV inverter. At each instant *t*, the maximum available reactive power capability, Q_t^{max}, can be calculated using (2.3).

$$Q_t^{max} = \sqrt{(S^{max})^2 - (\hat{P}_t)^2} \tag{2.3}$$

At every instant *t*, the Q_t^{max} is calculated with respect to the real power generation, $\hat{P}_t$, and the apparent power rating of the inverter S^{max}. This active and reactive capability, is also illustrated in Figure 2-5 (a) which shows the P-Q capability curve of a normal/common (i.e., here is illustrated considering $S^{max} = 1\ p.u.$) residential-scale PV inverter with a power factor capability of 0.9 (leading or lagging). As the figure shows, the reactive power capability of the inverter is directly influenced by the generation of the PV system ($\hat{P}_t$). More specifically, when considering the behaviour of the PV system through the day (influenced by the sun irradiance), Figure 2-5 (b) highlights that during periods of high generation (full irradiance, $\hat{P}_t =$

$1\,p.u.$), the inverter is not able to absorb or inject any reactive power posing an important limitation of the corresponding control functions during the periods where reactive compensation is most needed (to reduce voltages). It is worth mentioning that the aforementioned limitation can be overcome by oversizing the inverters and therefore being able to absorb/inject reactive power even at peak generation periods. This, however, entails higher costs to the end customers which might not be willing to cover.



(a) **(b)**

Figure 2-5 Power capability of normal residential-scale PV inverter

2.3.2 State of the Art

Considering the variety of already available control functions and the high flexibility of PV inverters to manage active and reactive power makes them desirable in mitigating technical issues such as voltage rise and thermal overloads. The majority of studies in [31-38, 74-81] focus on managing voltage issues adopting decentralised control methods whereas the number of studies investigating the adoption of centralised control methods is comparably lower [82-86]. These prominent published research studies are discussed in the following sections.

2.3.2.1 Decentralised Control

Given the lack of observability in LV networks and the nature of decentralised control approaches where actions are taken locally without the need of communication infrastructure, researchers have primarily focused on the decentralised management of voltage issues. A couple of studies, and more specifically in [79-81], investigate the adoption of decentralised active power curtailment methods (i.e., Volt-Watt, active power limit) to manage voltage issues where a stronger emphasis is given in the literature on the use of reactive power compensation through residential-scale PV systems to reduce (or eliminate) the corresponding voltage issues [31-38, 74-78].

2.3.2.1.1 Active Power Control

The adoption of the decentralised Volt-Watt control function (described in section 2.3.1.2) of residential-scale PV systems considering five different curves (from least to most sensitive in voltage changes), is investigated in [79] on three test LV feeders (based on real feeders in Belgium) with 62, 48 and 38 customers, respectively. Based on only three PV penetration level scenarios, the analysis showed that the investigated control method, considering all Volt-Watt settings, is able to keep all customer voltages within the statutory limits while also improving voltage unbalance issues. Nonetheless, while authors highlight the fact that the amount of energy curtailed is influenced by the adopted Volt-Watt settings, no detailed information is provided in terms of the amount of energy curtailed based on the different settings. The provision of such information is important as it allows DNOs taking more informative decisions when adopting the corresponding control scheme.

A more sophisticated decentralised control algorithm for PV systems that aims to manage local voltage issues through the active power curtailment of PV generation is presented in [80]. Using local measurements (i.e., voltage, power, weather, radiation) a short-term (i.e., 15 seconds) forecast (based on a Kalman filtering technique) is performed to check for potential overvoltage issues in the horizon. Using this forecast information, an estimation is also performed to evaluate if the overvoltage issue can be solved with reactive compensation. If not, then the amount of active power that is required to be curtailed is calculated for the corresponding PV system. The proposed method, which is validated using a modified IEEE 34-node test feeder with 2 PV systems, shows that it can effectively manage voltage rise issues. Despite the effectiveness of the proposed method, the validation considered a deterministic case with only two PV systems. Considering the extent of LV networks (e.g., circa 500,000 in the UK) and the number of PV systems installations, a significant effort might be required to model/program the corresponding forecast algorithm on each PV system making the adoption of such control method challenging to implement.

An interesting study in [81] combines the use of decentralised active (i.e., curtailment) and reactive power control of residential-scale PV systems to manage voltage issues in PV-rich LV networks considering five operation modes. During normal operating conditions (“mode 1”) where voltage is below a specified voltage (i.e., 1.07 p.u.) PV systems follow a specific Volt-Var curve to adjust their reactive power. As soon as “mode 1” of any PV system is not enough to maintain the voltage below 1.07 p.u. then “mode 2” is activated and a distress signal is sent to all PV systems that do not face voltage issues. Upon receiving the signal, all PV systems start absorbing reactive power based on a linear relation between the reactive power output and the remaining time until “mode 2” deactivation. If within the specified period of time, “mode 2” is not able to solve voltage issues, “mode 3” is activated where all PV systems start curtailing their generation based on a linear relation of the active power output and the remaining time until “mode 3” deactivation. Once the voltage issues are managed, “mode 4” is activated to smoothly restore the active power generation. “Mode 5” follows to restore reactive power in order to allow entering back in “mode 1”. The proposed method which was validated considering two test cases (single feeder and 14-feeder LV network), shows that important implementation settings like the duration period of “modes” and the Volt-Var curve settings are case specific as different settings were used for each test case. Consequently, the adoption of this control scheme might face implementation challenges as it will have to be tuned (i.e., settings) for each of the thousands of LV networks in a given region. Moreover, while the proposed method is based on the fact that it can be implemented without the need of extended communication infrastructure, some sort of investment is required to enable PV systems to transmit and receive overvoltage and distress signals, respectively.

While the adoption of active power control (i.e., generation curtailment) in PV-rich LV networks provides an effective voltage management and therefore increases the ability of LV networks to adopt more LCTs, there are a limited number of studies on this area. As this issue might be associated with the fact that the active power control of PV systems leads to reduced yields on PV system owners [87], current literature and researchers have put a significant effort in investigating the use of reactive power control of residential-scale PV systems to manage voltage issue.

2.3.2.1.2 Reactive Power Control

German studies in [28, 29], where the techno-economic comparison of the four most commonly available PV inverter power control functions (presented in section 2.3.1) is performed, highlight that the decentralised reactive power control, and particularly Volt-Var, is one of the most practical and economic approaches to adopt (see Figure 2-6). In addition, recent results from real pilot projects in Germany and Austria [74-76], “DG DemoNet Smart LV Grid” and “Active intelligent low-voltage network”, show that the adoption of decentralised Volt-Var control (combined with OLTC-fitted transformer) on German LV networks can provide effective voltage management. Nonetheless, considering that households in Germany and Austria are three–phase connected, it is unclear the extent of the benefits when adopting such control methods in LV networks where customers are mostly single-phase connected (e.g., UK, France, U.S.A). To provide more understanding on this matter, voltage rise caused by a single-phase connected PV system is considered to be approximately six times higher than the voltage rise caused by a three-phase connected PV system of the same power [38, 88, 89].

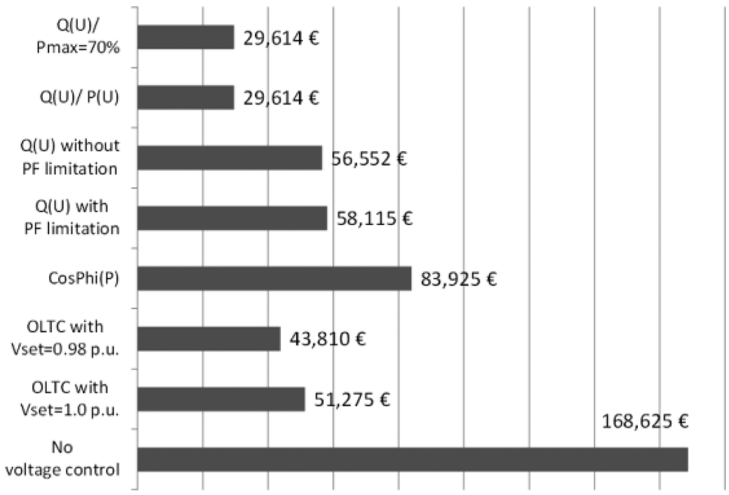


Figure 2-6 Investment cost of different voltage control strategies, on a German LV network [29]

An investigation of the benefits when adopting a decentralised Volt-Var control to manage voltage issues in single-phase household connections is presented in [77]. This work, having as the main objective to provide evidence on the ability of such control scheme to mitigate voltage rise, investigates the adoption of generic Volt-Var curves on representative U.S. feeders considering 15, 30 and 50% penetration level of residential-scale PV systems. Similarly, using another U.S. feeder with 11 PV systems, the work in [37] also assesses the performance of Volt-Var control adopting specific inverter set-points (i.e., Volt-Var curves). Although the results (see Figure 2-7) from both studies in [37, 77] although prove that voltage rise issues can be indeed mitigated with the adoption of Volt-Var control, authors do not give details on how adequate settings can be defined.

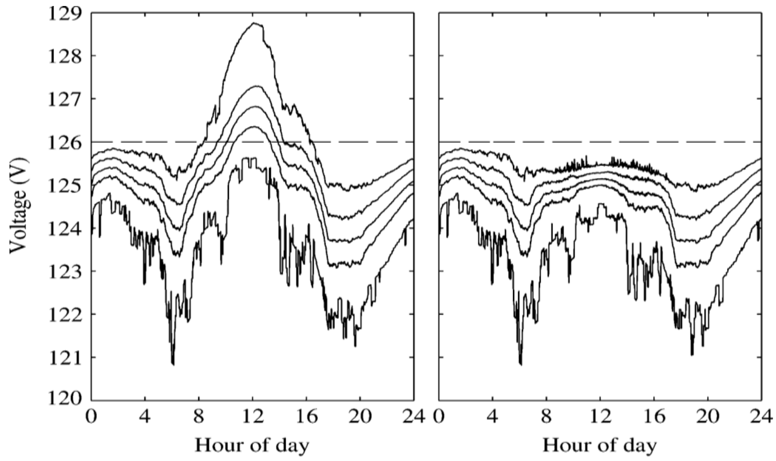


Figure 2-7 Customer voltages with 50% penetration of PV systems without (left) and with Volt-Var control (right) [77]

In the same vein of decentralised voltage management, authors in [31] move a step forward proposing a method to define optimal Volt-Var curves (i.e., set-points) for every individual PV inverter (22 in total) in a real Irish LV network with 74 single-phase connected customers. The performance of the optimal curves (in terms of voltage regulation), which are defined using a three-phase optimal power flow formulation (TOPF), is compared with a centralised active control scheme where the reactive power settings of the PV inverters are optimally defined in real time via a communication link. Even though results show that the adoption of optimal Volt-Var curves achieves almost the same performance with the centralised active control scheme, the analysis is performed considering only one specific PV penetration level (22 residential-scale PV systems in this case). Hence, it is unclear if the corresponding optimal Volt-Var curves will still be adequate considering a different PV penetration level or location of PV systems.

Adopting a similar approach to [31], the authors in [32] use a multi-objective genetic algorithm to define the optimal settings for each PV inverter in a real LV network (71 households) located in Bornholm Island, Denmark. The study, which aims to increase the hosting capacity of the LV network by adopting and comparing two decentralised reactive power control functions, $\cos\varphi(P)$ and $Q(V)$ (described in section 2.3.1) shows that the hosting capacity of the LV network can be indeed increased (up to 40% for the specific network) when adopting these methods. Out of the two, it was highlighted that the Volt-Var control, $Q(V)$, provides more effective voltage regulation than the power factor control, $\cos\varphi(P)$, possibly due to the fact that Volt-Var is acting based on the voltage level rather than the PV system's active power output. Although the application of optimisation approaches as in [31-35] (e.g., multi-objective genetic algorithm, TOPF) allows defining the most adequate settings for the adopted PV inverter control (thus better voltage management), it requires extended information of the LV network topology (not commonly available information to DNOs). This, unfortunately, limits their practicality and scalability given that the inverter settings have to be individually defined for the thousands of LV networks in a given region. Additionally, it should also be highlighted that the adoption of such methods might lead to significant computational times and increase the risk of not converging to a solution as the size of the optimisation problem significantly increases with network size and number of control variables.

More recently, a study performed in [38] tries to provide more understanding on different (on residential-scale PV systems) decentralised voltage control functions and concepts while investigating 28 different control settings (i.e., curves) for the Volt-Var controller. The study, which highlights the importance and effectiveness of the Volt-Var control function in managing voltage issues, shows that the most effective settings in managing voltage issues leads to a significant amount of reactive power absorption. Despite the effectiveness of the method, the effect of the increased current flow in the grid (due to reactive power) which might lead to the thermal overloading of network assets (i.e., cables, transformer) is not investigated. Additionally, as shown in Figure 2-8, the analysis is based on four simplified scenarios where the PV systems in the feeder are (1) uniformly distributed, (2) linearly increasing, (3) linearly decreasing and (4) all lumped at the end. More importantly, the analyses consider only two fictional continuous feeders with uniform impedance where all households and PV systems share the same profiles, respectively. Although the simplified case study allows proving the concept, in reality, however, feeders have numerous laterals with households (loads) and PV systems spread unevenly along the feeder. Subsequently, the investigated methods might overestimate the amount of reactive and active power that needs to be absorbed and curtailed, respectively. More importantly, this analysis, in [38], and several others, in [36, 37], assume PV inverters with ratings that can be high enough (i.e., oversized inverters) to maintain the full solar output (kWp) and the requested vars. However, as described in section 2.3.1.4 and shown in Figure 2-5, normal residential-scale PV inverters might have limited capability to inject or absorb the required reactive power (i.e., vars) in periods of high power output (i.e., sunny weather conditions). The available reactive power headroom is varying throughout the day (i.e., variable solar irradiance) and, therefore, might not be available when needed [77, 90].

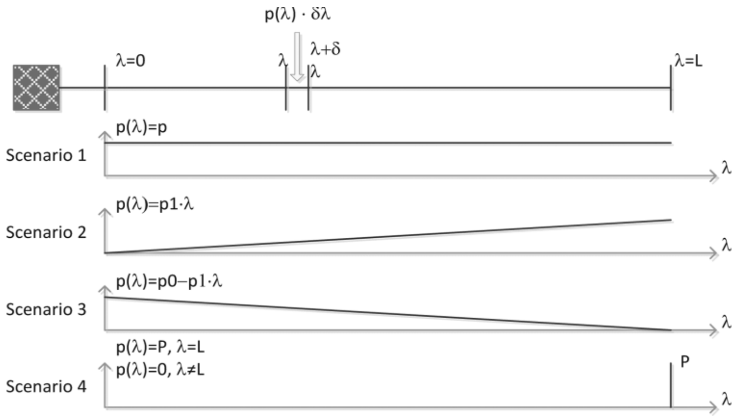


Figure 2-8 Investigated scenarios in [38]

Another recent study in [78], aims to provide a solution not only to voltage rise but also voltage drop and voltage fluctuation due to the cloud effects on PV generation. The authors propose and test a three mode reactive power controller for PV inverters on an Australian distribution system. The controller uses a reverse power flow versus reactive power droop characteristic for voltage rise mitigation during high PV generation. During normal operation (i.e., low or no PV periods), controller operates in “mode 1” which is a dynamic var control mode for voltage drop support. In periods of voltage rise (i.e., high PV generation), the controller operates in “mode 2” absorbing reactive power to mitigate overvoltage. “Mode 3” is initiated in moments of high voltage fluctuation (i.e., passing clouds) in order to mitigate fluctuations by ramp-rate control of inverter var output. While the analysis proves that the proposed method is effective in voltage management, the investigation was performed considering a specific penetration level of PV systems and no detailed information was provided on the curve settings used for the PV inverters. More importantly, the adoption of the proposed control function, that requires the PV inverters to use a reverse active power flow versus reactive power droop characteristic, might not be readily available in commercial PV inverters. Thus, the control logic will have to be programmed for each PV inverter, reducing its practicality and scalability.

Despite the evidence provided by the literature that the decentralised reactive compensation can indeed aid in mitigating voltages rise issues and, consequently, increase the hosting capacity of LV networks, none of the studies investigates the effect of increased current flowing in the network due to the absorption of reactive power. As a matter of fact, the majority of available studies either do not consider any thermal impacts or assume that the first impact resulting from high penetration of residential-scale PV systems is the voltage rise. Recent LV network impact studies [15, 23, 91], however, show that thermal overloading of assets (i.e., transformer and feeder segments) might occur simultaneously with voltage rise issues. In even more severe cases, thermal overloading of assets occurs before any voltage rise issue appears. Consequently, although the adoption of reactive compensation might help solving one issue (i.e., voltage rise), it is important to highlight that this may result in the increment of another (i.e., thermal overloading of the assets), as more current is flowing in the network due to the absorption of reactive power.

2.3.2.2 Centralised Control

Centralised control approaches, where control actions and set-points are provided through a central controller (usually located at the secondary substation), have always been an important part of the academic research and one of the most preferred control practices in managing electricity distribution networks. Considering that voltage rise due to the adoption of high penetration of residential-scale PV systems in LV networks is, as reported in [15, 22, 23], one of the most dominant technical issues, the literature has focused in providing centralised solutions with a primary aim to manage only voltage issues [82, 83]. Management of the thermal overloading of assets, however, which is also an important technical impact in PV-rich LV networks, has not been thoroughly addressed [84]. More importantly, centralised solutions that consider both technical impacts simultaneously are limited [85, 86].

Starting with [82], a centralised real-time active power capping method is proposed to manage voltage rise issues in distribution networks with high penetrations of PV systems. To achieve that, every PV system (within a distribution network) considers a voltage threshold where, if violated, a signal is sent to all PV systems instructing them to start recording their active power outputs and voltages. Based on consecutive measurements a linear relationship between the voltage and active power is created for each PV system to then use and forecast the maximum active power output (generation cap) that can be allowed without resulting in voltage rise issues. Using this information, the centralised controller calculates and sends back a new generation limit for all PV systems that aims to share the generation curtailment among all of them (fair curtailment). Authors who highlight the implementation challenges associated with the required communication infrastructure between PV systems and the central controller also propose a technique to adopt the same method on a decentralised approach. However, a communication between neighbouring PV systems is still required.

Having the same goal (voltage management), authors in [83] propose a centralised control method that it can optimally define the active and reactive power output of residential-scale PV systems in unbalanced PV-rich LV networks. Using a multi-objective optimal power flow, the proposed method aims at reducing the corresponding voltage issues while reducing the amount of active power curtailment by providing priority to reactive power absorption. To reduce complexity, the use of the weighted-sum method is adopted to convert the multi-objective problem into an aggregated single-objective. Its performance is assessed on an Australian test LV network (based on Perth Solar City) with 77 single-phase connection customers and 34 residential-scale PV systems (i.e., 32% of PV penetration level). The results show that, indeed, voltages can be effectively managed with minimum curtailment while also reducing the voltage unbalance effect. However, to achieve the corresponding performance, the study considered 60% over-sized PV inverters to enable the absorption of reactive power even at peak generation otherwise not possible with normal inverters (as discussed in section 2.3.1.4). While over-sized PV inverters provide significant benefits to DNOs (e.g., voltage management) they are associated with higher costs (that customers might not be willing to pay) compared to normal and commercially available residential-scale PV inverters. Furthermore, the adoption of this control scheme requires a two-way communication which entails a major investment in communication infrastructure.

While all previously discussed studies aim at managing voltage issues, authors in [84] propose an optimisation method for thermal management in LV networks with high penetrations of LCTs (i.e., PV systems, electric heat pumps). In this study, residential customers who own a PV system are assumed to have a contract with the local DNO where they specify a percentage of their total generation that is allowed to be curtailed (i.e., non-firm capacity) while the rest should be maintained at all times (i.e., firm capacity). Based on this firm and non-firm generation capacity, a real-time optimisation method (using mixed integer programming) is proposed to minimise the amount of active power required to be curtailment in order to keep the utilisation of assets (i.e., transformer, feeder cables) within limits. The performance of the proposed method, which is investigated on a 16-bus Dutch LV network with full penetration of PV systems, is compared with other 4 different curtailment methods and rules in which PV systems should contribute to the curtailment (e.g., selection based on power flowing in the feeders, security constrained OPF). As expected, the proposed method achieves the goal (i.e., thermal management) with minimum curtailment compared to the investigated methods.

To provide a more complete solution, the same authors, propose in [85], the combination of their proposed centralised thermal controller with a decentralised active power control method to manage both thermal and voltage issues in PV-rich LV networks, simultaneously. The decentralised PV control approach which is based on a P-V droop characteristic is acting in real-time to manage voltage issues where the centralised controller, based on 15-min control cycles, is checking for thermal violations. Once identified, the optimisation problem is solved with the current network state to provide the optimal active and reactive settings for the PV systems. The analysis, which is based on the same case study in [84], considerers a multi-agent system-based control scheme to perform coordination and communication between the different network components (i.e., transformer, feeders, customers and PV systems). This unfortunately, reduces the scalability and practicality of the corresponding method as it requires complex communication infrastructure and full network observability (currently not available in LV networks).

Using a similar approach (optimisation algorithm), the work in [86] also proposes an on-line centralised controller that aims in managing both voltage and thermal issues simultaneously. To perform the optimisation method, a state estimation is performed to obtain the voltages at each bus. Then using sensitivity coefficients, the network's active and reactive power injections are estimated to become an input to the optimisation problem and finally define the active and reactive power for each PV system in the network. Although the application of distribution state estimation technique is likely to have a good accuracy, it requires extended information of the LV network topology as well as the number and type of connected low carbon technologies. Consequently, this might pose a significant challenge as the corresponding estimator has to be tailored to each of the thousands of LV networks in a given region.

More importantly, almost all of the centralised control approaches available in the literature apply complex optimisation algorithms to calculate the optimal active and reactive power settings of each PV system [83-86]. As a result, extensive information/visibility of the network is required which in reality is not available. Hence, a significant investment is required to develop the corresponding monitoring and communication infrastructure that will enable the successful implementation of the corresponding control schemes.

2.3.3 Summary of Gaps in Literature

The wide amount of recent studies suggests that the control of residential-scale PV systems to manage voltage issues in PV-rich LV networks is a topic undergoing intense study. While the work on centralised control methods in LV networks is limited, the adoption of decentralised control methods has attracted more attention, giving emphasis on the reactive power control of PV inverters. Based on the studies discussed in section 2.3, the most important gaps found in the current literature and addressed in this Thesis are highlighted and summarised below:

1. An in depth analysis on the effects of different set-points (i.e., curves) for both Volt-Watt and Volt-Var control functions is not covered in the literature. While a detailed analysis of the effects will enable DNOs to take more informed decisions when adopting these controls, it will also allow identifying universal settings suitable for all PV penetration levels.

2. None of the papers in the literature considers the effects from the increased current flow when absorbing reactive power in LV networks. Although the absorption of reactive power might help to solve one issue (i.e., voltage rise), it might result to the increment of another (i.e., thermal overloading of assets).

3. The majority of papers assume PV inverters with ratings that can be high enough (i.e., oversized inverters) to maintain the full solar output (kWp) and the requested vars. In reality however, commercially available residential-scale PV inverters might have limited capability to inject or absorb the required reactive power (i.e., vars) in periods of high power output (i.e., sunny weather condition). Hence, realistic studies that consider this important limitation are required to understand the extent to which this control function can help to manage voltage issues.

4. The majority of centralised control methods proposed in the literature use complex optimisation techniques that might not only require significant investments in network monitoring (not available in LV networks) and communication infrastructure but also lead to significant computational times and increase the risk of not converging to a solution as the optimisation problem significantly increases with network size and number of control variables. Consequently, practical, cost-effective and scalable solutions that use limited and already available information need to be explored.

5. Almost all studies are based on managing only voltage issues and, in general, aim to solve issues separately. An integrated, practical and scalable solution that manages both voltage and thermal issues simultaneously is required.

2.4 Residential-scale Battery Energy Storage Systems

Residential-scale BES systems (up to ~20 kWh) have been recently introduced by several manufacturers (e.g., Tesla, LG, ABB, SMA) [92-95] to help householders reducing their electricity bills by storing the excess of PV generation (i.e., generation minus demand) during the day and using it later at night [39, 40]. The aforementioned behaviour is illustrated in Figure 2-9 where the orange shaded area represents the potential energy (i.e., excess of PV generation) that could be stored and then used during the night (purple shaded area). This behaviour can essentially decrease the customer's dependence from the grid as less energy is required to be supplied by the latter, and therefore reduce the corresponding electricity bills.

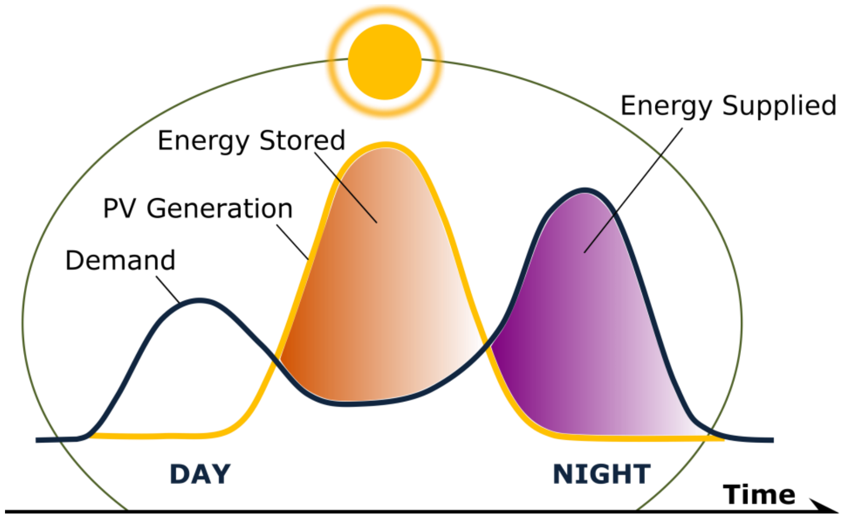


Figure 2-9 Interaction between residential-scale PV and BES system

As a matter of fact, Moixa Energy, a UK-based company which aims to install 1 million residential-scale BES systems across all UK by 2020, is claiming that each household can actually save up to £350 per year in electricity bills using the technology [96, 97]. The adoption of residential-scale BES systems has already gained significant interest during the last few years given the reduction of feed-in tariff rates for residential-scale PV systems, particularly in countries with rapid PV installation rates (i.e., UK, Germany, Italy) [98, 99]. To give an example, UK customers today receive £0.049 per kWh they export (generated from PV systems) into the grid, and pay £0.14 per kWh imported [100]. This significant difference in price is the main factor that incentivises customers to adopt residential-scale BES systems in order to store the excess of their locally generated energy (i.e., PV systems) and use it at a later time rather than exporting it into the grid. Indeed, a recent report on the energy storage market in Germany highlights that the declining feed-in-tariffs, along with the high electricity prices (47% increase since 2006), are the major drivers for the energy storage market growth; which is forecasted to exceed the annual value of 1 billion USD by 2021 [101].

In addition, the market growth is also expected to increase even more as several DNOs are now imposing fixed, network-wide limits on PV exports (i.e., generation minus demand) in an effort to reduce technical impacts due to high PV penetrations. In these cases, residential-scale BES systems will allow to store and use the corresponding energy above the imposed limit which would otherwise be curtailed (due to imposed export limits). To give some examples, in Germany, where more than one million PV systems are connected in LV networks, customers with installed capacities smaller than 30 kWp are not allowed to export more than 70% of their installed capacity [98]. Similarly, DNOs in Australia and Hawaii impose export limits to new PV system installations [102, 103].

If the future energy storage market predictions are correct, then large amount of technical innovation on this technology is required to exploit all of its possible applications. This is also evident through recent European [104] and government level [105, 106] innovation funds, aiming to provide innovation on this technology, and also through already launched energy storage projects [107-110]. Moreover, DNOs see this new technology as a potential tool that can help mitigate impacts associated with the excess of PV generation (e.g., voltage and thermal issues), thus providing an alternative solution to reinforcement.

One of the first pilot projects in California, US, which installed 5kW/7.7kWh BES systems in fifteen households with PV systems, investigated how the technology can help reducing the peak demand through load shifting [107, 108]. Although the project faced technical problems with some equipment, forcing a number of BES systems to go offline, it was shown that storage can indeed smooth the peak load while also reducing the electricity bills of the corresponding customers. Another project in Newington, Australia, which was set to investigate the use of residential-scale BES system (i.e., 4kW/10 kWh) in a household with PV system and electric vehicle, showed that even though it is able to reduce the household's net imported energy from the grid, it is unable to fully charge the electric vehicle [109]. In the UK, the low carbon network fund (LCNF) project Sola Bristol ran by Western Power

Distribution (WPD) aimed to investigate the adoption of residential-scale BES systems (i.e., 2kW/4.8kWh) in households with PV systems to reduce peak electricity consumption and manage thermal overloads [110]. Using variable tariffs to incentivise customers using the battery, the project showed that indeed the electricity consumption can be reduced. However, it was highlighted that further work is essential to exploit additional benefits of this technology.

2.4.1 State of the Art

Given that the use of residential-scale BES systems in LV networks is relatively a new concept, literature in this area is currently, as expected, limited [41-46, 111]. The majority of available studies focus on control schemes that provide benefits only to the DNOs (i.e., voltage management, load peak shaving) and use complex optimisation techniques to achieve their goals [41-46]. On the other hand, studies that consider customer benefits (i.e., increased self-consumption, electricity bill reduction) are very limited and more importantly, the provision of control schemes that considers both the customers and DNO benefits is yet to be explored [111].

2.4.1.1 Network-oriented Research

Authors in [41] investigate the potential of installing a BES system to manage technical impacts on LV feeders with a primary goal to increase their ability to host more PV systems. The analysis is performed using a multi-objective optimisation function that aims to manage voltages and reduce the peak load power while considering the cost of the BES system required to be installed. The proposed method, which is assessed on a real feeder with 62 residential customers and 30% of PV penetration, first identifies the optimal location for the BES system to be installed to then solve the multi-objective optimisation problem. Based on different objective values, the authors create pareto-optimal isocost curves that determine the corresponding BES system cost based on the required performance (i.e., peak shaving, voltage regulation). As expected, it is highlighted that the adoption of the BES system is able to manage voltage issues, hence increase the hosting capacity; however a trade-off between the objectives (i.e., peak power reduction and voltage management) is required in order to define the most adequate size for the BES system.

To manage voltage issues in PV-rich LV networks, authors in [42] propose a control scheme that allows DNOs to control the BES systems of residential customers to provide reactive compensation during specific time periods in exchange for a subsidy covering part of the BES system cost. Based on an optimisation function and using a synthetic MV feeder with aggregated LV customers, authors demonstrate that the proposed approach provides adequate voltage management. While this method shows promising results, it requires BES systems to reduce their charging power rate during periods of voltage issues so that the inverter (of the BES system) will be able to absorb reactive power (limitation of commercial inverters discussed in 2.3.1.4). This, unfortunately, might limit the amount of energy that the corresponding battery can store during the day.

The work in [43] proposes three optimisation-based (i.e., centralised, decentralised, distributed) and a rule-based control algorithms for residential-scale BES systems in order to reduce the variability in the power profile in LV networks. The first algorithm, which is based on a centralised controller, considers full network observability and communication to estimate the load and generation. These estimations are then used to optimally solve a model predictive control (MPC) problem to define the charging/discharging behaviour of each BES system in the LV network. The second algorithm, which considers a decentralised controller installed in every BES system, adopts the same approach with the central controller but only using local measurements and no communication. The third algorithm considers a hierarchical distributed control approach where each BES system is communicating with a central hub (i.e., Market Maker) that provides real-time prices of selling and buying power to or from the grid according to a network-wide objective (i.e., reduce the variability demand – flatten the power profile). Lastly, the forth algorithm considers a rule-based controller that manages the charging/discharging of BES systems according to the household's net demand profile. The performance of the proposed controllers was assessed considering 2kWh residential-scale BES systems as well as Australian generation and demand data. As expected, results showed that the centralised controller achieves the best performance in terms of flattening the power profile; however this method becomes immediately infeasible as the size of the optimisation problem increases with network size. While the decentralised and distributed control approaches, that do not require excessive network observability and communication, achieve similar performance (with the centralised), they both rely on predictions of demand and generation to solve the proposed MPC problem. This, however, increases implementation challenges as the proposed methods require historical data and case-specific settings to solve the MPC problem. As for the rule-based controller, it was highlighted that it does achieve the corresponding objective (i.e., reduction of power profile variability). Although the rule-based controller increases the practicality of the proposed method, no quantification was provided in terms of voltage issues and more importantly all proposed methods ignore the customer's primary goal when adopting a residential-scale BES system; to increase self-consumption therefore reduce electricity bill.

To manage voltage issues in LV networks, authors in [46] adopt a slightly different approach. Their proposed method aims to calculate the minimum required BES system capacity able to manage voltages issues by defining a household export limit and forcing the BES system to charge based on the power that exceeds that limit. The proposed method, which is investigated on a Danish LV network considering three penetrations (i.e., 50, 75, 100%) of 3-phase connected residential-scale PV systems, proves to be effective in managing voltage issues. However, the assumption of 3-phase connected PV systems does not highlight the issues associated with heavily unbalanced phases which are common in many other European countries (i.e., UK, France). Moreover, while the proposed method efficiently solves the corresponding voltage issues, the energy stored in the BES systems is not quantified and is unclear if this method maximises the usage (i.e., reaching 100% state of charge) of the BES systems for the customer's benefit. Consequently, this reduces its profitability as the stored energy might not be enough to cover the household demand during the night.

Another approach in [45], similar to the previous study, proposes a control method to manage voltages in LV networks by forcing the BES systems to start charging only once a predefined power threshold is reached. To define the corresponding power threshold an optimisation problem using linear programing is solved. The proposed method, which is assessed on a Belgian LV feeder considering 23 and 50% of PV penetration level, highlights that the power threshold is case specific as it depends on factors such as the penetration and location of PV systems and the network topology. This, unfortunately, limits the scalability of the corresponding method as a power threshold is required to be defined for each LV network. More importantly, similar to [46], the proposed method does not ensure that the BES systems will store the maximum available energy during the day as they charge only to manage voltage issues. This, however, limits the primary goal of the residential-scale BES systems which is to reduce the owner's electricity bill by storing the maximum available excess of PV generation and using it later in the day.

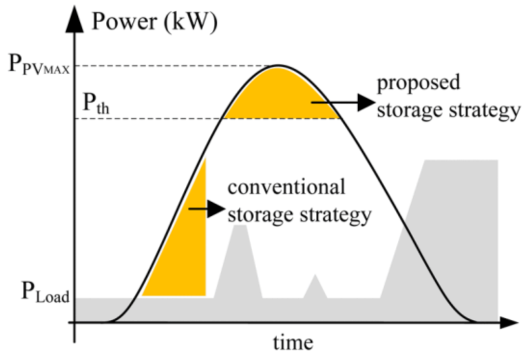


Figure 2-10 Conventional storage strategy and proposed strategy in [45]

Despite the effectiveness of the studies described in [41-43, 45, 46], all of them use optimisation algorithms to adequately control residential-scale BES systems and, therefore, achieve their objective (i.e., voltage management, peak shaving). This, however, as mentioned in section 2.3.2, increases the complexity and poses a significant implementation challenge as it entails extensive investments to provide the required monitoring and communication infrastructure in LV networks.

More recently, and in the context of providing more practical BES control schemes, without the need of advanced communication infrastructures, authors in [44] propose a decentralised control method that makes use of the reactive capability of PV systems combined with a droop-based charging/discharging control of BES systems to manage voltage issues in LV networks. The proposed method assumes that PV systems will continuously provide reactive compensation (based on their reactive capabilities) and that the BES systems will start charging, based on voltage-power droop curve, only once a critical voltage is reached. Considering a case study of a residential feeder with 12 houses all equipped with 6kWp PV systems, the authors investigated the performance of the proposed method adopting two scenarios where: 1) a universal droop curve is used for every BES systems, and, 2) a different droop curve is used for each BES systems (to ensure uniform energy storage). The results show that both cases achieve efficient voltage management; however, the first case requires customers located at the end of the feeder to install larger BES systems (i.e., up to 5kWh) as they face higher voltages (thus more frequent charging) compared to customers located closer to the substation. On the other hand, the second case shows that if a specific droop curve is used for every BES system, a smaller battery size (i.e., up to 2kWh) is required to be installed, given that everyone contributes to the to the voltage management (uniform charging). Nonetheless, to define the corresponding droop curves an off-line voltage sensitivity analysis considering the corresponding LV network is required which makes the approach case specific. Additionally and similar to the previously discussed studies, the charging of BES systems is only activated once a critical voltage level is reached. This, however, limits the ability of the BES systems to store any excess of PV generation during periods or days where there are no voltage issues (i.e., not very sunny days).

2.4.1.2 Customer-oriented Research

Research considering the control of residential-scale BES systems for the customer's benefit (i.e., reduce electricity bills) is limited. Nonetheless, the study in [111] provides a thorough analysis that evaluates the economic potential of using a residential-scale BES system, given the falling feed-in tariffs for residential-scale PV systems and considering a range of variables: the electricity price forecast, battery costs forecast, load demand response and BES system lifecycle. Using Australian demand and generation data, the optimal size of the BES system (i.e., 5kWh) is defined based on a 2.5kWp PV system which is assumed to be the most common size in Australian residential installations. Once the size is defined, an optimal charging/discharging operation is developed adopting state space dynamic programing. This optimal operation is essentially maximising the profitability of the BES system (i.e., minimisation of the total cost of electricity use) using future predictions of load and generation. Then adopting the corresponding optimal operation, the payback period for the technology is calculated considering different BES sizes and costs per kWh capacity. The analysis highlights that residential-scale BES systems can indeed become economically viable in the foreseeable future (i.e., around 2020), given the continuous rise in electricity prices and the decreasing BES system costs.

Despite the thorough analysis of the economic potential of using residential-scale BES systems in LV networks, the study considers only specific size of residential-scale PV systems and therefore the stochastic variability of PV sizes, which can be found in LV networks, is not accounted. In addition while the analysis considers the cost of the BES system, it does not take into account costs associated with the corresponding installation. Crucially, the proposed optimal BES system operation relies on optimisation and perfect prediction of generation and demand which might increase the implementation complexity as historical data and network information is required.

2.4.2 Summary of Gaps in Literature

In general, the literature shows a strong interest on trying to define the most adequate control algorithm (i.e., charging/discharging operation) for residential-scale BES systems depending on the desired objective. The majority of studies discussed in section 2.4.1, focus on controlling residential-scale BES storage systems to manage technical issues in PV-rich LV networks. In these studies, the primary goal of the residential-scale BES systems (reduce customer electricity bills) is not addressed thoroughly and in some cases is not even considered. This, however, creates an important gap between academic research and real practice as most of the customers might not be willing to use their BES systems only to manage technical issues. Based on the research discussed in section 2.4, the most important gaps found in the current literature and addressed in this Thesis are highlighted and summarised below:

1. A deep realistic analysis of the normal (i.e., out of the box) operation of residential-scale BES systems considering different penetrations of residential-scale PV systems in LV networks is required. This will allow identifying potential limitations of this technology and help develop solutions catering for those.

2. Almost all of the studies found in the literature apply complex optimisation techniques to define the optimal operation of residential-scale BES systems. These, unfortunately, require significant investments in network monitoring and communication infrastructure. Consequently, practical, cost-effective and scalable solutions that use limited and already available information are needed.

3. Control schemes for residential-scale BES systems that take into account both the benefits of customers (i.e., increase self-consumption, thus reduced electricity bills) and DNO (i.e., voltage and thermal management) are yet to be explored. It is essential to develop control algorithms that aim to maximise the amount of energy stored in BES systems during the day while managing technical issues (e.g., voltage and thermal issues).

2.5 LV OLTC-fitted Transformers

Due to the passive nature of LV networks around the world (i.e., unidirectional power flow, thus no controllable elements), transformers in secondary distribution substations (e.g., 11kV/0.4kV or 6.6kV/0.4kV in the UK, 20kV/0.4kV in France) are designed with transformation ratios high enough to compensate voltage drops according to the worst case scenario (i.e., maximum load conditions without considering PV generation). More importantly these transformers are equipped with off-load tap changers [16-19] which means that the ratio between the primary and the secondary voltage can only be changed after disconnecting the load [112, 113]. Consequently, once a given off-load tap position has been found to be adequate for the corresponding LV transformer loading conditions, it is very unlikely that this setting is changed in the lifetime of the transformer (unless the customer composition of the network itself changes significantly).

Considering the above, the last point of voltage regulation in distribution networks is traditionally performed at the primary distribution substations (e.g., 33/11kV or 33/6.6kV in the UK) which are equipped with OLTC-fitted transformers [16-19]. The principle of voltage regulation on distribution networks, as illustrated in Figure 2-11, is to maintain the voltage at the secondary side (point A) close to a predefined voltage target (commonly above the nominal) so that the voltage of all connected customers in the medium (MV) and low voltage feeders (particularly those connected in the far end, point D) is within the statutory limits during maximum load (dark blue line) [21]. However, given the pre-defined settings (i.e., tap position) of off-load tap changers and the relatively high transformation ratio of transformers in LV networks, the connection of large numbers of residential-scale PV systems may result in voltages significantly higher than the upper statutory voltage limits (i.e., point D in Figure 2-11) during minimum load (red line).

Crucially, the degree to which voltages can be reduced or increased is constrained due to the voltage compliance of medium voltage (MV) customers and the thousands of customers connected in the LV networks [114]. Thus to increase the 'on-load' flexibility in LV networks the use of LV OLTC-fitted transformers can be considered as a potential solution to manage voltages closer to LV customers and therefore increase the corresponding PV hosting capacity. Indeed, German techno-economic studies in [29], highlight that the adoption of OLTC-fitted transformers in LV networks (compared to traditional network reinforcement) can be both a technical and economically viable solution to manage voltages.

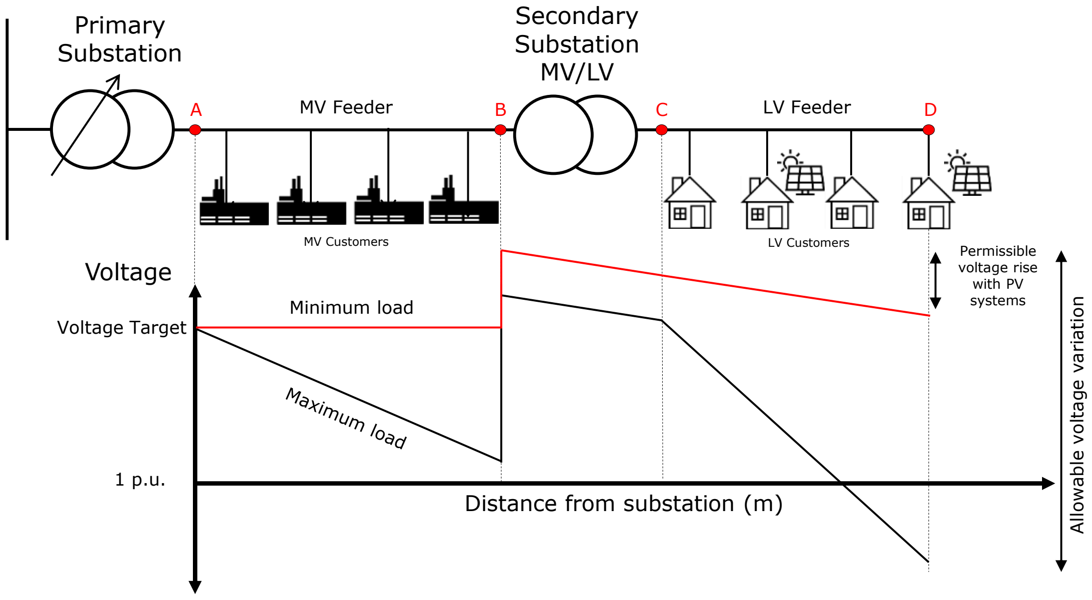


Figure 2-11 Voltage variation in radial distribution feeder [21]

2.5.1 Transformer and OLTC Operating Principles

To understand how OLTC-fitted transformers can help in actively managing voltages closer to LV customers, the basic operation of transformers and OLTCs is discussed in the following sections.

2.5.1.1 Transformer Operating Principle

The operation of a transformer is based on the principles of electromagnetism to change an AC voltage level to another. Its basic operation principle, which is detailed in [115], is illustrated in Figure 2-12 which demonstrates a two winding ideal transformer. If voltage is applied (V_p) on a conductor (e.g. transformer primary winding), the resulted alternating current (I_p) flowing in the conductor will create a changing magnetic field, flux Φ, around the conductor which can induce a voltage (V_s) to another conductor ends (e.g. transformer secondary winding) connected also in the same magnetic field. The resulted voltage magnitude (V_s) on the secondary winding depends on the turns ratio (N_p/N_s) of the transformer. For example, if the secondary winding has half the number of turns of the primary winding, then the voltage on the secondary winding will be half the voltage across the primary winding. Therefore, the secondary winding voltage, step up or down, can be approximated using (2.4).

$$V_s = \frac{V_p}{N_p} \times N_s \quad (2.5)$$

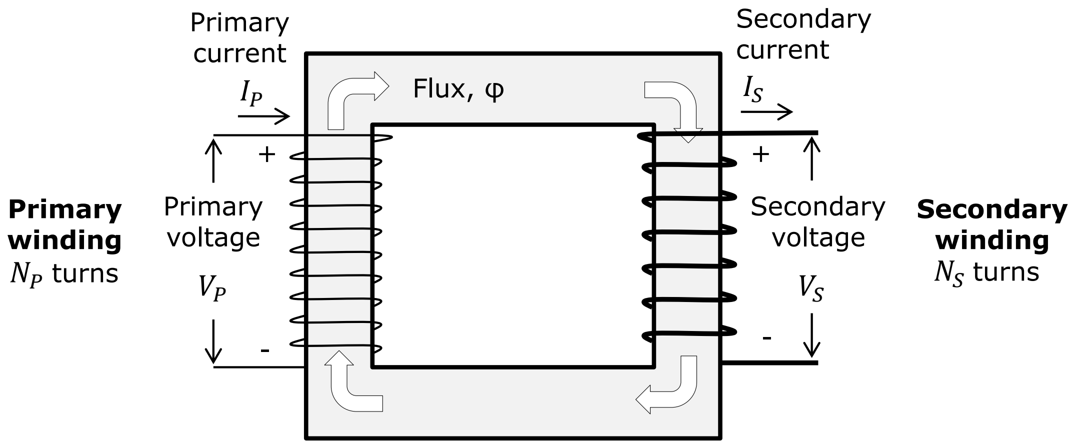


Figure 2-12 Basic transformer operation (ideal transformer)

OLTC-fitted transformers, using a mechanical device, are able to change the number of turns to be used, in discrete steps. Hence, this ability can offer the advantage to change the transformation ratio according to the available tap positions. This allows voltage adjustments at the substation, under loading conditions, to increase or reduce the voltage level.

2.5.1.2 OLTC Operating Principle

OLTCs are typically installed on the primary side of transformers and they are controlled by the Automatic Voltage Control (AVC) relay which uses voltage measurements from the secondary side of the transformer to define the corresponding control actions (i.e., tap change). This operation is illustrated in Figure 2-13 where a voltage transformer (VT) measures the voltage on the secondary side of the transformer (i.e., V_s) [116]. This measured voltage is always compared with a pre-defined voltage target and no regulation is performed if it is within the defined bandwidth settings (defined based on acceptable voltage variations). Once the measured voltage deviates from the bandwidth, the AVC sends a signal to the OLTC in order to change the tap position (i.e., up or down). To avoid excessive tap changes due to short period voltage deviations (e.g., a few seconds) the tap change signal is delayed.

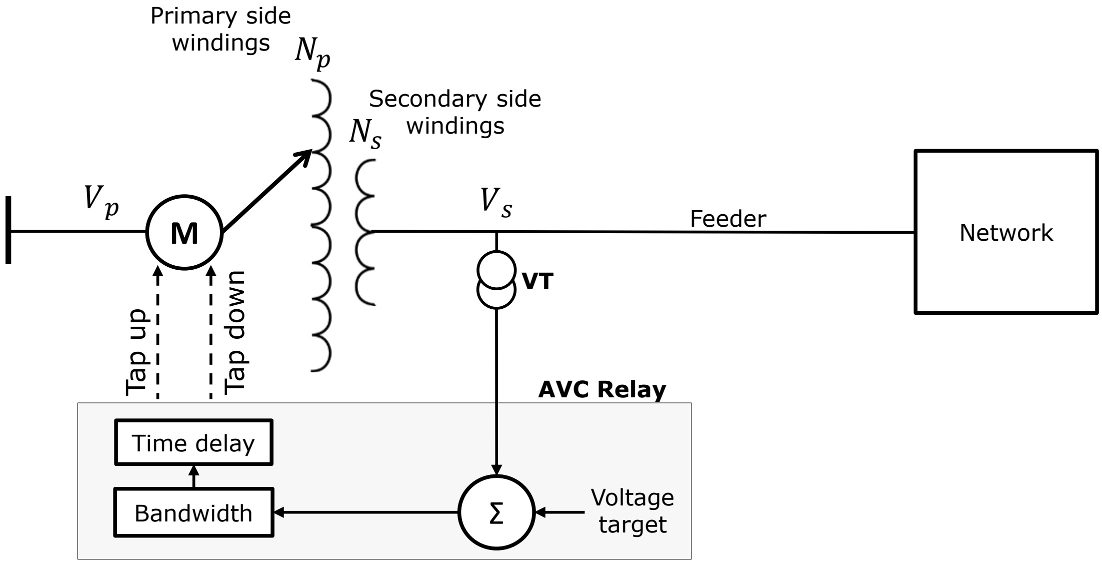


Figure 2-13 Voltage control using OLTC

2.5.2 State of the Art

The adoption of LV OLTC-fitted transformers has been recently considered as a potential solution to manage voltage issues in PV-rich LV networks. Although the OLTC is considered to be a well matured technology and widely used at higher voltage levels (e.g., 33/11kV or 33/6.6kV in the UK) [19], its adoption in LV networks is relatively a new concept and requires a thorough investigation given the complexity of LV networks (i.e., unbalanced connection of load and generation, high penetrations of LCTs, bidirectional power flow, rapid voltage deviations due to PV systems). The majority of studies found in the literature investigate rule-based control approaches that combine the use of OLTC-fitted transformers with other controllable devices (i.e., residential-scale PV systems, capacitors, in-line voltage regulators) to manage voltage issues [28, 74, 76, 113, 117-123]. Some others use more complex optimisation techniques to achieve the same goal [124-126].

Germany is perhaps the first country to adopt the use of LV OLTC-fitted transformers. This is mainly because of the large volumes of residential-scale PV systems resulting from their feed-in-tariff incentives. The German DNO EnBW Regional AG trailed the use of LV OLTC-fitted transformers and in-line voltage regulators in two German LV networks (i.e., Freiamt, Sonderbuch) [117, 118]. The control approach considered a load-depended adjustment of the OLTC voltage target (i.e., changed according to the total load variation) and the control of in-line voltage regulators based on the feeders reverse power. This approach however, requires some understanding of the topology and feeders impedances to approximate the corresponding relationship between power and voltage. It is also important to highlight that the approach requires the installation of additional devices (i.e., in-line voltage regulators) in the feeders; hence increasing cost and potentially limiting its deployment due to practical aspects (e.g., space for in-line voltage regulators).

Another pilot project in [76], "Active intelligent low-voltage network", ran by the German DNO E.ON Mitte AG investigated the use of OLTC-fitted transformer in combination with PV systems reactive power control to manage voltage issues in an LV network in Felsberg-Niedervorschütz. Although the project showed that effective voltage management can be achieved with the proposed approach, emphasis was primarily given on the reactive compensation through PV systems which does not highlight the extent to which OLTC-fitted transformers can help to manage voltage issues in PV-rich LV networks.

The pilot project DG DemoNet–Smart LV Grid investigated the application of different control approaches to manage PV related voltage issues in an Austrian LV network (i.e., Eberstalzell) using a LV OLTC-fitted transformer combined with reactive compensation from residential-scale PV systems [74, 119-121]. The control approaches included 1) OLTC control with local (i.e., substation) monitoring only, 2) OLTC control considering line drop compensation and local monitoring only, 3) OLTC control considering line drop compensation and reactive power control of PV systems, and 4) OLTC control considering real-time smart meter data. The project, as expected, highlighted that the higher visibility provided by smart meters (i.e., voltages) can offer a better voltage regulation through the OLTC. However, no detailed information is provided on the adopted OLTC control algorithm and the analysis considered only one PV penetration level (i.e., 173 customers with 60 residential-scale PV systems). Additionally the analysis did not assess any impacts related to different control cycle lengths and the corresponding quantification of tap changes. The quantification of these parameters is important in order take more informative decisions when adopting such methods.

Similarly, authors in [113] propose a coordinated control of an LV OLTC-fitted transformer with reactive power compensation through PV inverters to manage voltages in a typical German LV network. The proposed OLTC control algorithm makes use of remote monitoring data (i.e., voltages) at critical points in the feeders to then perform a test in order to check if a tap up or down can bring the maximum and minimum voltages within the statutory limits. Results show that voltages can indeed be managed with the proposed control strategy; however, the work was limited only to some deterministic cases of a specific PV penetration level. This, unfortunately, does not provide the full picture of potential scenarios (i.e., different penetrations and locations of PV systems). More importantly, the effect of the proposed method only quantified the voltage at a specific network point rather than considering the voltage at all customer connection points.

In [122, 123], authors investigate the effect of using a voltage range as a control input for OLTC-fitted transformers aiming to reduce the number of tap changes required to manage voltage issues in distribution networks. However, to define the corresponding voltage range at the busbar, knowledge of important feeder characteristics is essential (i.e., impedance, number of connected customers, and penetration level of PV systems). Consequently, the adoption of such an approach will have to be tuned for each network; hence, reducing its scalability.

A more detailed analysis in terms of the provision of simulation-based results considering the techno-economic assessment of different voltage control strategies including the adoption of OLTC-fitted transformers in LV networks is presented in [28]. In this study, the OLTC controller uses information from the two most critical network points (where the maximum and minimum voltages occur), to then trigger a tap change. For example, a tap change (up or down) is triggered if the voltage at one of the monitoring points is outside a predefined voltage bandwidth and the process is repeated until the corresponding monitored voltage falls back within the bandwidth limits. Nonetheless, as the OLTC control actions are triggered based only on one of the two measurements, a significant challenge might arise when both monitored voltages (max and min) are outside the bandwidth. Although the study, which considers a real German LV network (i.e., 122 households, 12 PV systems), shows that voltage issues can be managed with the proposed method, the analysis was limited only to a few demand and generation snapshots rather than a time-series analysis. More importantly, the performance is quantified considering only the "weakest" network point instead of the all customer connection points.

Several other studies propose the use of more complex techniques to provide coordination between the LV OLTC-fitted transformer and the residential-scale PV systems [124-126]. In [124], for example, authors propose an optimisation method that uses load and irradiance forecast to provide an optimal reactive power control of PV systems while reducing the number of tap changes required by the OLTC-fitted transformer. Similarly, authors in [125] propose an optimisation method to manage voltage issues while minimising the corresponding feeder losses. Considering the study in [126] a model predictive control (MPC) strategy that uses simplified grid models to predict future voltage variations is proposed to control LV OLTC-fitted transformers aiming to manage voltage issues n PV-rich LV networks. Although the application of these techniques (i.e., optimisation, MPC, forecasting) is likely to have a better performance in terms of voltage management and number of tap changes, they require extended information of the LV network topology, the number and type of connected LCTs as well as the deployment of costly communication infrastructures. This, unfortunately, creates significant deployment challenges as this information might not be readily available to DNOs. Furthermore, these methods have to be tailored to each of the thousands of LV networks in a given region.

An interesting and more recent study, based on the UK pilot project “LoVIA” [47], proposes the coordinated control of LV OLTC-fitted transformer and capacitor banks to manage contrasting voltage issues (i.e., one feeder with voltage rise and other with voltage drop) in LV networks [112]. The study proposes three control strategies where in the first two 1) a constant and 2) a time-based controlled voltage target (for the OLTC) is considered. The third control strategy considers 3) a rule-based OLTC controller which automatically updates the voltage target every control cycle, based on remote end monitoring points at each feeder. To manage contrasting voltage issues, the study proposes the use of capacitor banks to boost the voltage in those feeders experiencing significant voltage drop issues. The study, which considers a year-long stochastic analysis on real UK LV network with 351 residential customers and different PV penetration levels, highlighted that the adoption of an OLTC-fitted transformer in the investigated network can help to delay voltage issues to 50% of PV penetration (compared 30% when using off-load tap changer, i.e., no control). Although a comparable performance in terms of voltage management is achieved with all proposed methods, the rule-based controller results to the lowest number of tap changes. Despite the complete analysis and effective performance of the study, the proposed rule-based control method uses fixed compensation factors which have to be defined considering the voltage step of the each OLTC tap change, thus making the adoption of this method case specific. In addition, the method does not take into account the effect (in terms of voltage) of the new voltage target on the other remote monitoring points.

2.5.3 Summary of Gaps in Literature

Based on the studies available in the literature and discussed in this section, it is evident that the adoption of OLTC-fitted transformers can be a potential solution to manage voltage issues in LV networks. The most important gaps found in the current literature and addressed in this Thesis are highlighted and summarised below:

1. The majority of studies in the literature consider German and Austrian LV networks (i.e., customers with three-phase connections). Consequently and as previously mentioned in section 2.3.2.1.2, the performance adopting an LV OLTC-fitted transformer must also be investigated in the context of single-phase customer connections to quantify the potential benefits in other LV networks (e.g., UK, France, USA).

2. Almost all studies in the current literature focus on control strategies that consider the coordinated control of LV OLTC-fitted transformers with other controllable technologies (e.g., residential-scale PV systems, in-line voltage regulators, capacitors). This, however, does not highlight the extent to which OLTC-fitted transformers alone can help to manage voltage issues in PV-rich LV networks.

3. The case studies performed in the literature are mostly limited to deterministic power flow analyses that consider specific PV penetration levels. Some others, even more limited, considered only several snapshots of load and generation profiles. Stochastic time-series analyses considering different PV penetrations levels and high granularity (e.g., scale of seconds and minutes) demand and generation profiles are essential to truly assess the performance of OLTC-fitted transformers in LV networks.

4. The literature highlights that in order to efficiently manage the busbar voltage and, consequently, the customer voltages, measurements across the LV network

are required to visualize its state. However, measurements in LV networks are typically non-existent and, therefore, information about the network state is not available. Consequently, remote monitoring at strategic points in the network can provide visibility of voltages close to the customers' connection points. However, considering the large number of LV networks around the world, it is crucial to understand the extent to which monitoring and its location can benefit the performance the OLTC-based voltage control.

5. The majority of studies in the literature do not quantify the number of tap changes. High number of tap changes can lead to the OLTC wear and tear [124], therefore the effects of the corresponding OLTC control settings, such as control cycles, is essential to be investigated.

6. A scalable and adaptive OLTC control logic that aims in managing contrasting voltages issues, rise (due to the presence of generation) and drop (due to loads) is yet to be developed.

Chapter 3

Control Schemes for PV-Rich LV Networks

3.1 Introduction

This chapter provides the details of the control schemes proposed in this Thesis aiming at managing voltages and/or thermal issues in PV-rich LV networks. Section 3.2, presents the proposed control approaches to actively manage residential-scale PV systems, while sections 3.3 and 3.4 correspond to the management of residential-scale battery energy storage systems and LV OLTC-fitted transformers, respectively.

3.2 Residential-scale PV Systems

This section details the control approaches to actively manage residential-scale PV systems. Sub-section 3.2.1 corresponds to the proposed decentralised control of residential-scale PV systems aiming to manage voltage issues in LV networks while sub-section 3.2.2, provides details of the proposed centralised controller that aims to manage thermal issues. Sub-section, 3.2.3, proposes the combination of the centralised and decentralised controller to manage both thermal and voltage issues in LV networks.

3.2.1 Decentralised Voltage Control

As mentioned in section 2.3, modern inverters installed in residential-scale PV system installations are already embedded with fast (i.e., fraction of second) power control functions that can be used to manage voltage issues in a decentralised way; thus requiring no communication infrastructure. Indeed, the literature shows that the use of already embedded control functions (i.e., Volt-Var, Volt-Watt) in residential-scale PV inverters can offer efficient voltage management. Nonetheless, an in depth analysis (e.g., voltage compliance, utilisation of assets, energy curtailment etc.) investigating the effects of different Volt-Var and Volt-Watt set-points (i.e., curves) might have in an LV network, is not covered in the literature. This analysis can provide important insights to DNOs, allowing them to take more informed decisions when adopting these decentralised power control functions. More importantly, such investigation will potentially allow identifying a single set of Volt-Var or Volt-Watt curve settings that can effectively manage voltage issues in any LV networks.

To bridge this important gap, this Thesis proposes a Volt-Var and Volt-Watt analysis to investigate the effects of different set-points (i.e., curves) for each power control function. To enable this investigation, this section presents how the corresponding Volt-Var and Volt-Watt set-points (i.e., curves) can be defined (details in section 5.2).

3.2.1.1 Volt-Var Set-points

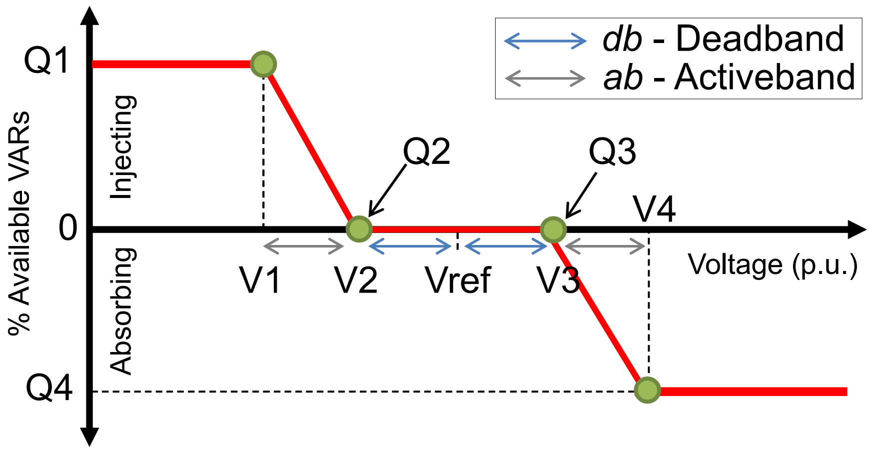


Figure 3-1 Volt-Var curve adjustable settings

The PV inverter Volt-Var set-points are provided in the form of a Volt-Var curve (Figure 3-1). This curve, depending on the DNO requirements is defined by a variable number of points (commercial inverters usually support up to 6 points) as shown in Figure 3-1. In order to design this curve, the p.u. middle point of the statutory voltage limits is used as a reference point ($Vref$). Then based on a p.u. “deadband” value (db) $V2$ and $V3$ can be calculated using (3.1) and (3.2), respectively.

$$V2 = Vref - db \tag{3.1}$$

$$V3 = Vref + db \tag{3.2}$$

$V1$ and $V4$ can then be calculated using $V2$, $V3$ and the specified ‘‘activeband’’ (ab) as shown in (3.3) and (3.4), respectively.

$$V1 = V2 - ab \tag{3.3}$$

$$V4 = V3 + ab \tag{3.4}$$

For example, the set-points can be defined such that the inverter provides maximum possible reactive power at the full range of allowable voltage ($V1$ to $V4$), or possibly a more narrow range of set-points to provide much more conservative voltage regulation. The reactive power output values (i.e., $Q1$, $Q2$, $Q3$, and $Q4$) are defined as a percentage of available vars given the present active power output and the reactive power capability of the PV inverter.

3.2.1.2 Volt-Watt Set-points

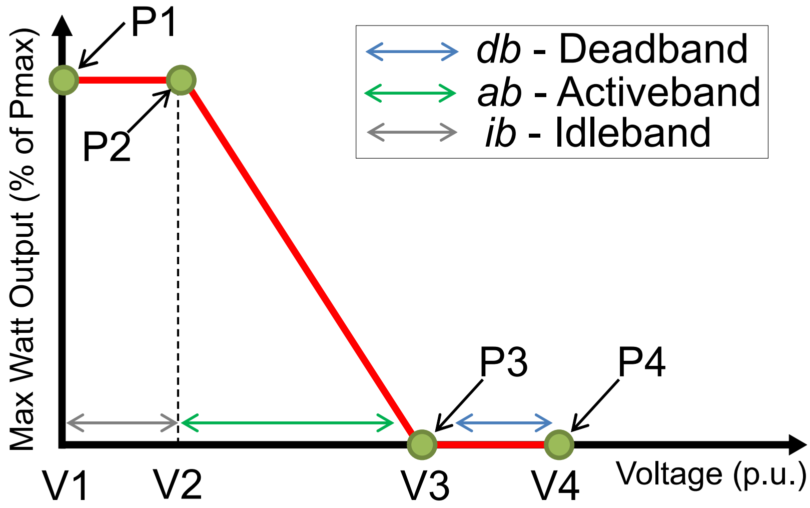


Figure 3-2 Volt-Watt curve adjustable settings

The PV inverter Volt-Watt set-points are also provided in the form of a Volt-Watt curve (Figure 3-2). This curve, depending on the DNO requirements is defined by a variable number of points (commercial inverters usually support up to 6 points) as shown in Figure 3-2. In order to design this curve the p.u. middle point of the statutory voltage limits is also used as a reference point ($Vref$). Then based on a p.u. "idleband" value (ib) V1 and V2 can be calculated using (3.5) and (3.6), respectively.

$$V1 = Vref \tag{3.5}$$

$$V2 = V1 + ib \tag{3.6}$$

$V3$ and $V4$ can then be calculated using the $V2$ and the specified ''activeband'' (ab) and ''deadband'' (db) as shown in (3.7) and (3.8), respectively.

$$V3 = V2 + ab \quad (3.7)$$

$$V4 = V3 + db \quad (3.8)$$

The active power output values (i.e., $P1$, $P2$, $P3$, and $P4$) are defined as a percentage of the maximum PV power output (i.e., Pmax).

3.2.2 Centralised Thermal Control (CTC)

The vast majority of studies found in the literature focus on voltage management only; ignoring the fact that reverse power flow can result in the thermal overloading of the most expensive network assets (i.e., transformer, feeders/cables). Considering this important gap, along with the ones summarised in section 2.3.3, an innovative and scalable centralised controller is proposed here aiming to manage thermal issues in PV-rich LV networks. Compared to other methods that use complex optimisation techniques and require significant investments in communication infrastructure and network monitoring, the proposed method considers a rule-based controller using limited network observability (i.e., substation measurements only). Consequently, the proposed control logic offers significant benefits to DNOs as it does not require the installation of remote monitoring points; thus, reducing the need of costly communication infrastructure.

3.2.2.1 Control Architecture

Figure 3-3 shows the implementation architecture of the proposed centralised thermal control logic. Sensors are installed at the head of LV feeders (i.e., at the substation) to monitor the 3-phase active power for each feeder and phase.

A pyranometer located at the substation monitors the per unit clear sky irradiance as well as the one that can be seen on the PV panels. With the control logic programmed in a programmable logic controller, PLC, (also located at the substation), the known installed PV capacity per feeder (and per phase) and the monitored data transferred to the PLC, it is possible to compute the active power limit set-points (flat universal signal) for PV systems (per feeder) so that the total PV generation will not lead to transformer or feeders thermal overloads.

These active power limit set-points can then be transmitted (e.g., radio, dedicated lines, WiMAX) through a device and picked up by the corresponding group of receivers installed on PV inverters. Here, a group of receivers is considered to be the

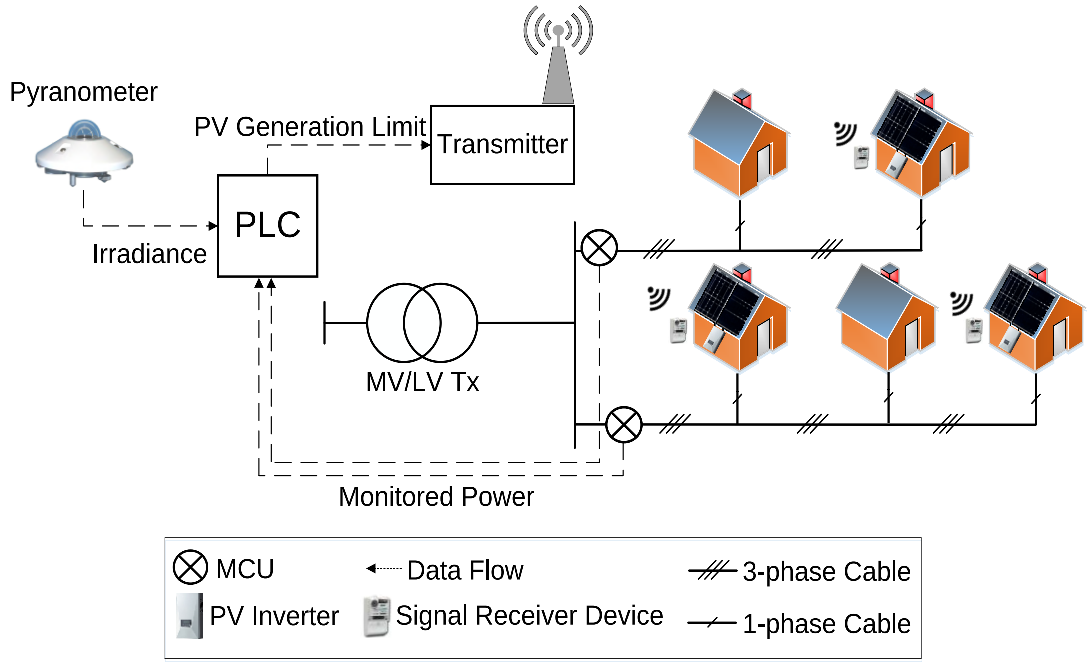


Figure 3-3 Monitoring and Control Architecture

group of PV inverters located in a specific feeder. Thereafter, PV inverters adopt the received active power limit set-points.

<u>Possible Communication Infrastructure</u>

It is important to highlight that the implementation of such control scheme does not require new complex and costly communication infrastructure as active power limit set points can be sent using existing communication infrastructure such as the European radio ripple control [127, 128]. European radio ripple control is a low data rate long wave (VLF) broadcast system presently used in Germany and Hungary for various energy related applications such as [129]:

- Remote control of street lighting (lighting management)
- Power plant load management
- Customer tariff switching and load management

<u>Radio Ripple Control Implementation Details</u>

The transmission coverage radius by a single VLF transmitter is typically 300 to 500km thanks to ground wave propagation along earth curvature. Users (i.e., DNOs) of the European (or any other country) radio ripple control can send their control signals to the host computer via integrated services digital network (ISDN) or via the Internet. The control signals are then transmitted based on communication protocols [128] (e.g., Versacom, Semagyr) and picked up by the corresponding receivers [130, 131] installed at each PV inverter.

Each receiver has an individual address and continuously monitors every broadcast signal. If the signal being sent has an address that matches the address of the receiver, the receiver interprets the message. Otherwise, the message is ignored. In addition, "group level" addressing can be used where groups of receivers respond to the same address.

Considering the extensiveness of LV networks around the world and the corresponding number of PV system groups, it is also important to highlight that this communication infrastructure can be beneficial as it can address millions of individual devices. For example, the Versacom protocol (also known as DIN 43861-401 Type A) which is one of the major transmission protocols used can have up to 9x8 bits of address or 72 bits (i.e., a total of 2^{72} addresses).

3.2.2.2 Control Logic

The proposed control logic algorithm is divided into 2 stages.

Stage 1, considers the feeders, where the aggregated demand is estimated for each feeder ($P_{F_{n_\varphi}}^{demand}$, per phase) using local measurements at the substation. Once the aggregated demand is estimated a check is performed to identify the most loaded phase ("worst") of a feeder in order to deal with unbalance issues. Based on aggregated demand, in the corresponding phase, the available PV generation headroom (i.e., the maximum amount of generation that will not lead to overloading) is calculated. Using this headroom ($P_{F_{n_\varphi}}^{PV\_Headroom}$), along with the known PV installed capacity, the active power limit set-point ($pctP_{F_n}^{s.p.}$ in %) is calculated in order to limit the generation of all PV systems in the corresponding feeder. The new calculated active power limit set-point ensures that the generation of PV systems will not lead to feeder overloading.

Stage 2, considers the transformer where a check is performed to identify if it will face any thermal issues when settings from Stage 1 are applied. If true, the excess generation ($P_{TX}^{PV\_Excess}$) required to be reduced and a new active power limit set-point ($pctP_{F_n}^{s.p.}$ in %) for each feeder is recalculated. The final active power limit set-point ensures that both transformer and feeders will not overload.

Every control cycle i (depending on the supported telecommunication infrastructure) the monitored active power per phase ($P_{F_{n_\varphi}}^{mon}$ in kW, where $\varphi \in [a, b, c]$) and the monitored irradiance are collected. The installed PV capacity per feeder ($IC_{F_n}^{PV}$) and per phase ($IC_{F_{n_\varphi}}^{PV}$) is assumed to be known.

The two stages of the control logic algorithm are detailed in the following subsections and the flowchart of each stage is presented in Figure 3-4 and Figure 3-5, respectively.

<u>Stage 1 – Feeder Level</u>

First, using (3.9) the aggregated demand is estimated for each feeder ($P_{F_{n_\varphi}}^{demand}$, per phase) using local measurements at the substation. These measurements are the active power ($P_{F_{n_\varphi}}^{mon}$ per feeder/phase), the p.u. irradiance ($E_{p.u.}^{PV}$) seen on the PV panels, and the known installed PV capacity ($IC_{F_{n_\varphi}}^{PV}$, per feeder/phase).

$$P_{F_{n_\varphi}}^{demand} = \begin{cases} P_{F_{n_\varphi}}^{mon} + \left(pctP_{F_{n_{i-1}}}^{s.p.} \times IC_{F_{n_\varphi}}^{PV} \right) & , pctP_{F_{n_{i-1}}}^{s.p.} < E_{p.u._i}^{PV} \\ P_{F_{n_\varphi}}^{mon} + \left(E_{p.u._i}^{PV} \times IC_{F_{n_\varphi}}^{PV} \right) & , pctP_{F_{n_{i-1}}}^{s.p.} > E_{p.u._i}^{PV} \end{cases} \tag{3.9}$$

Thereafter using the monitoring data at the head of each feeder ($P_{F_{n_\varphi}}^{mon}$), the most loaded phase (in case of reverse power flow) for each feeder is identified. This, as previously stated, is performed in order to deal with possible unbalance situations where one phase has more (or less) PV systems or loads than the other two. Therefore, any set-points that will eventually solve technical issues for the ‘‘worst’’ phase, they will also solve technical issues for the other two phases. Once this ''worst'' phase is identified, the algorithm calculates the available generation headroom ($P_{F_{n_{\varphi}}}^{PV\_Headroom}$) using (3.10). This headroom is the maximum amount of generation that the corresponding phase can support without overloading.

$$P_{F_{n_{\varphi}}}^{PV\_Headroom} = \left| P_{F_{n_{\varphi}}}^{demand} + \left(a \times P_{F_n}^{max} \right) \right| \tag{3.10}$$

where a corresponds to a threshold (e.g., 1.0 which corresponds to a 100% of the cable capacity $P_{F_n}^{max}$).

Using the available generation headroom ($P_{F_{n_{\varphi}}}^{PV\_Headroom}$) and the phase installed PV capacity ($IC_{F_{n_{\varphi}}}^{PV}$) the algorithm calculates the active power limit set-point ($pctP_{F_n}^{s.p.}$) using (3.11).

$$pctP_{F_{n_i}}^{s.p.} = \frac{P_{F_{n_{\varphi}}}^{PV\_Headroom}}{IC_{F_{n_{\varphi}}}^{PV}}, \qquad \begin{cases} 0 & , if \;\; pctP_{F_{n_i}}^{s.p.} < 0 \\ 1 & , if \;\; pctP_{F_{n_i}}^{s.p.} > 1 \end{cases} \tag{3.11}$$

The $pctP_{F_n}^{s.p.}$ is essentially the percentage of the value to which the maximum rated output power of all PV systems in the specific feeder will be limited to in order to keep the feeder's utilisation level at or below 100%.

Lastly, the worst case loading ($P_{F_n}^{Loading}$) is estimated using the calculated $pctP_{F_n}^{s.p.}$, the estimated demand ($P_{F_{n_{\varphi}}}^{demand}$) and the clear sky p.u. irradiance ($E_{p.u._i}^{clear}$).

$$P_{F_n}^{Loading} = \begin{cases} \left(pctP_{F_{n_i}}^{s.p.} \times IC_{F_n} \right) - P_{F_n}^{demand} & , if \;\; pctP_{F_{n_i}}^{s.p.} < E_{p.u._i}^{clear} \\ \left(E_{p.u.}^{clear} \times IC_{F_n} \right) - P_{F_n}^{demand} & , if \;\; pctP_{F_{n_i}}^{s.p.} \geq E_{p.u._i}^{clear} \end{cases} \tag{3.12}$$

Stage 2 – Transformer Level

Once the active power limit set-points for each feeder and worst case loading of each feeder are calculated, stage 2 essentially checks if the settings defined by Stage 1 will not lead to transformer overloading. Therefore, if the worst case loading of the transformer exceeds the transformer's capacity (P_{TX}^{max}) then the additional generation to be reduced is calculated using (3.13).

$$P_{TX}^{PV\_Excess} = \begin{cases} \sum_{1}^{N} P_{F_n}^{Loading} - (a \times P_{TX}^{max}) & , if \sum_{1}^{N} P_{F_n}^{demand} > (a \times P_{TX}^{max}) \\ 0 & , if \sum_{1}^{N} P_{F_n}^{demand} \leq (a \times P_{TX}^{max}) \end{cases} \tag{3.13}$$

If $P_{TX}^{PV\_Excess}$ is higher than zero it means that the generation has to be limited even more. In that case the $pctP_{F_n}^{s.p.}$ is recalculated for each feeder using equation (3.14) to distribute the additional generation curtailment among all PV systems. Otherwise, $pctP_{F_n}^{s.p.}$ remains the same as calculated in Stage 1.

$$pctP_{F_{n_i}}^{s.p.} = \begin{cases} \dfrac{(\, pctP_{F_{n_i}}^{s.p.} \times IC_{F_n}) - \dfrac{P_{TX}^{PV\_Excess}}{N\, feeders}}{IC_{F_n}^{PV}} & , if \;\; pctP_{F_{n_i}}^{s.p.} < E_{p.u._i}^{clear} \\ \dfrac{(E_{p.u._i}^{clear} \times IC_{F_n}) - \dfrac{P_{TX}^{PV\_Excess}}{N\, feeders}}{IC_{F_n}^{PV}} & , if \;\; pctP_{F_{n_i}}^{s.p.} \geq E_{p.u._i}^{clear} \end{cases} \tag{3.14}$$

Finally, the active power limit set-points ($pctP_{F_n}^{s.p.}$) are rounded down to the nearest integer. Once this is done, active power limit set-points are sent to the corresponding group of PV inverters. This process is carried out every control cycle. The control cycle is a parameter to specify how often the logic will provide a control, if necessary. In an x-min control cycle, the average monitored data of the last x minutes will be used for the algorithm. To give an example, if a 10-min control cycle is considered then, the monitored data of the last 10 minutes will be used for the control logic algorithm.

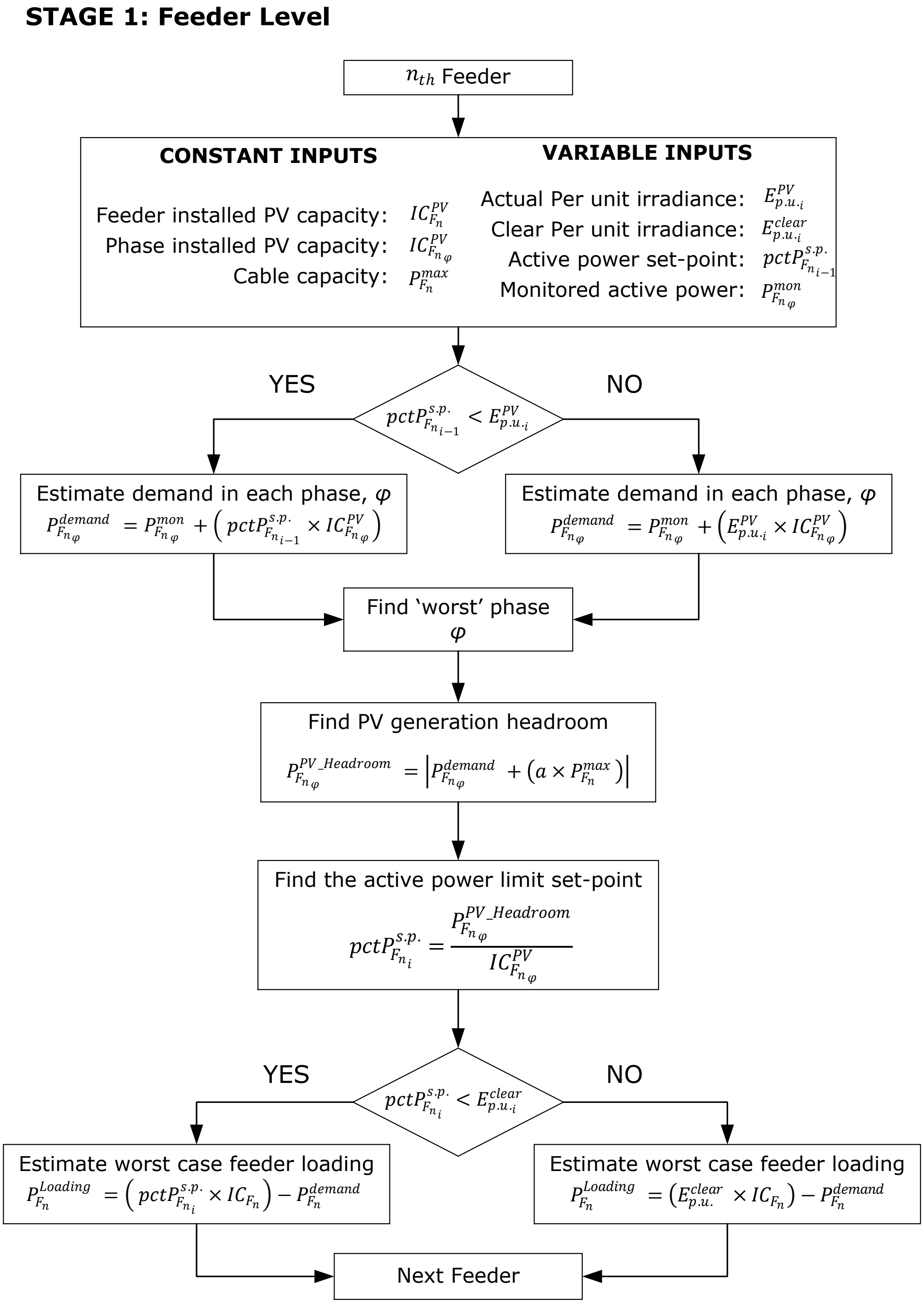


Figure 3-4 Centralised Thermal Control Flowchart (Stage 1)

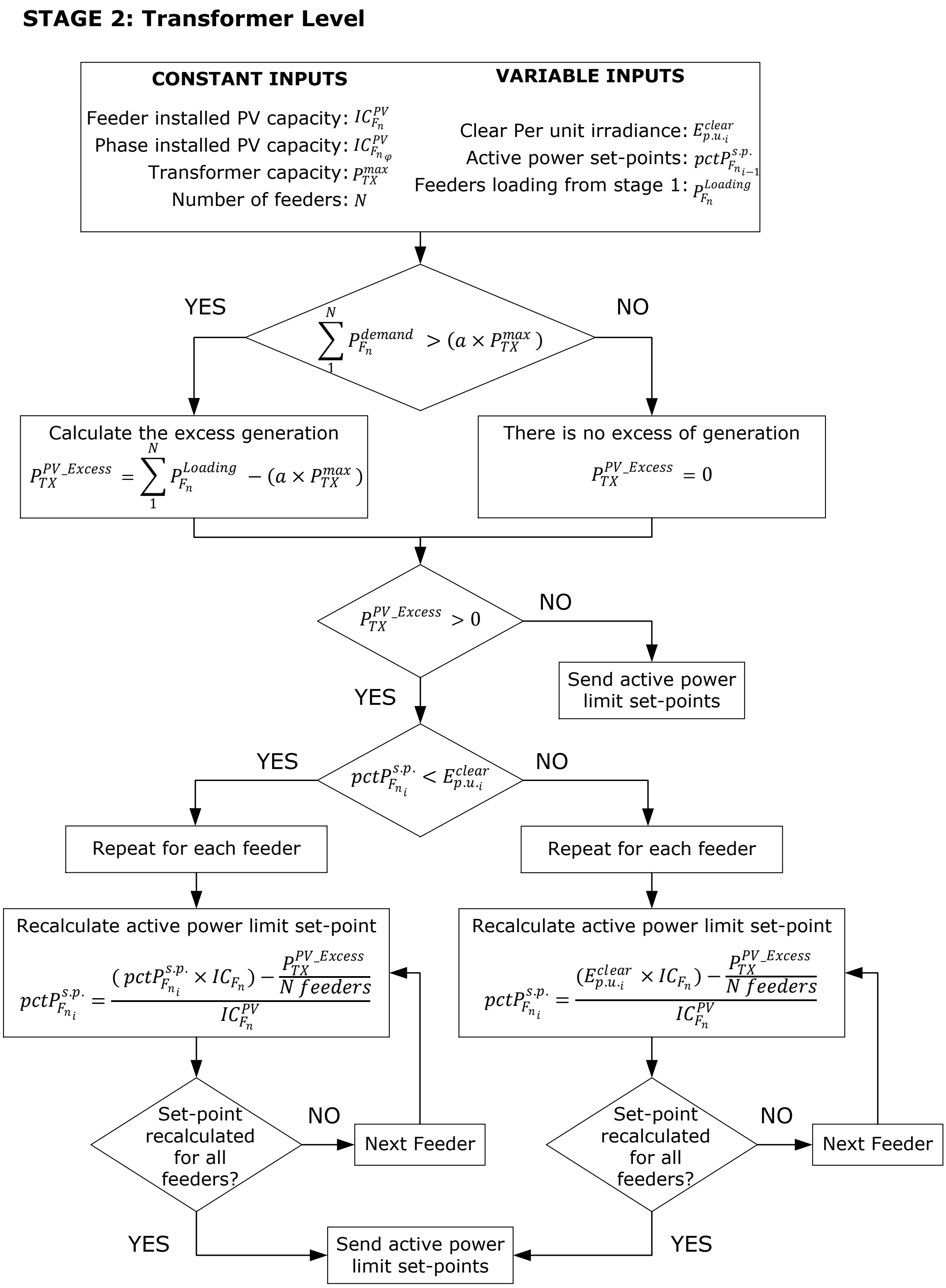


Figure 3-5 Centralised Thermal Control Flowchart (Stage 2)

3.2.3 Combined Centralised Thermal and Decentralised Voltage Control

Section 2.3, highlighted that almost all studies performed in the literature are based on managing voltage issues only and, in general, aim to solve issues (e.g., voltage, thermal) separately. Even though a limited number of studies [85, 86] propose solutions to simultaneously manage voltage and thermal issues, they lack practicality and scalability as they are based on complex optimisation techniques that require extensive network observability and need to be tuned for each of the thousands of LV networks in a given region.

To provide a complete active network management, aiming to solve both thermal and voltage issues, this section proposes the combination of the centralised thermal control (presented in section 3.2.2) with the decentralised Volt-Watt support. The centralised thermal control essentially aims to manage thermal issues while the decentralised control (i.e., Volt-Watt control function) aims to manage voltage issues. The proposed control method, unlike other not-easy-to-implement solutions (i.e., complex optimisation algorithms, increased network visibility), offers a more cost-effective, scalable and practical alternative as it requires limited network observability (i.e., substation measurements only).

3.2.3.1 Control Logic

The previously described centralised thermal control logic (presented in section 3.2.2) and Volt-Watt control are used simultaneously. For the latter, a curve is adopted that considers the highest voltage ‘‘*idleband*’’ so curtailment only occurs when strictly needed. This curve can also be selected considering a Volt-Watt analysis (performed in case study section 5.4). All PV inverters (in the network) are set up to follow the same curve, which takes action only if the voltage (at the connection point) is higher than V2 (see Figure 3-2). It is also important to highlight that the centralised thermal controller signals are applied first so that the Volt-Watt control is limited only to the active power limit specified by the centralised thermal controller. This is achieved as the inverter is continuously checking in real-time (i.e., fraction of a second) if there is any signal to change the active power limit. If a signal is detected, the active power limit is updated first on the PV inverter and then the Volt-Watt function adopts the new maximum generation point ($P1 = P2 = P_{max} \times pctP_{F_n}^{s.p.}$, see Figure 3-2) from the corresponding Volt-Watt curve. The change of active power limit is applied within the range of milliseconds from the moment it is received; hence, latency issues in terms of the Volt-Watt function are negligible.

3.3 Residential-scale Battery Energy Storage

This section provides the details of the proposed advanced operation mode for residential-scale BES systems aiming to bring benefits to both customers (i.e., reduced grid dependency, hence reduced bills) and DNOs (i.e., voltage and thermal management). First, sub-section 3.3.1 presents the "normal operation" mode, i.e., the control mode likely to be adopted by manufacturers for householders to make the most of their PV systems. The latter is used as a base case to assess the performance of the proposed "advanced operation" mode which is presented in sub-section 3.3.2.

3.3.1 Normal Operation Mode

Although several residential-scale BES systems are currently available in the market, the exact details of their "normal operation" mode are not available; manufacturers only provide general descriptions related to the basic operating principles of their products [93, 132]. Hence, based on the most common operating principles of commercial BES systems as well as information found in the literature [133-135], the following two basic rules are considered to be adopted by the industry:

1. Charging/discharging cycles during the day should be kept low in order to maintain the lifespan of the BES system. Allowing multiple cycles per day significantly reduces the BES system's lifespan [136, 137] as it can support approximately 3,000 to 5,000 full cycles [94, 95, 138, 139].

2. The battery should only charge from the excess PV generation and, unless otherwise specified, will only discharge during load-led periods.

Considering the above two rules and according to manufacturer's operation specifications [93, 132], the "normal operation" mode is adopted in this Thesis, and used as the base case to compare and assess the performance of the proposed "advanced operation" mode (detailed in section 3.3.2).

3.3.1.1 Description

The normal operation mode considers only one cycle per day, i.e., one charging and discharging period and the adopted operation is described as follows:

- **Charging period.** Occurs during daylight as soon as the PV system generates electricity. During this period, the BES system always charges the excess of PV generation (i.e., negative net demand). The charging period ends once the PV generation is zero.

- **Discharging period.** Occurs only when the PV system is not generating (i.e., night time). During this period, the BES system discharges with a power rate equal to the household's demand (i.e., follows demands). The discharging period ends once the PV system starts generating again the following day (i.e., new charging period).

3.3.1.2 Illustrative Example

In order to demonstrate the normal operation of a BES system, Figure 3-6 is used as an illustrative example showing the demand, PV generation and BES system charge/discharge behaviour of a household with a 3kWp PV system and a 3.3kWp 10kWh BES system. The example considers 2 consecutive sunny days. For simplicity, the same generation and demand profiles are assumed for each day.

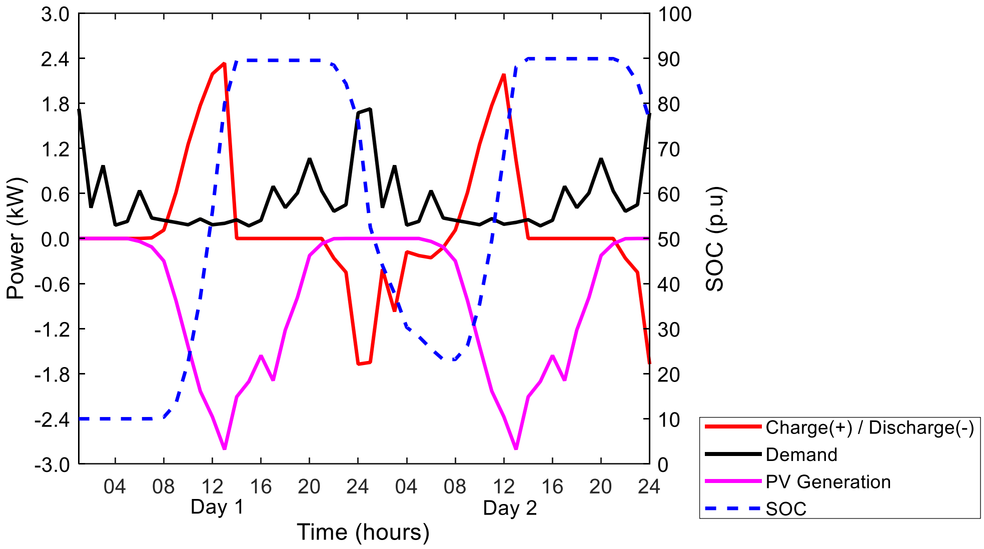


Figure 3-6 Illustrative example of normal operation mode

The first day of the example is assumed to be the first day where the BES system is installed at the household and, therefore, its state of charge (SOC, dashed blue line) is considered to be equal to the lower battery reserve limit (i.e., 10%). Upper and lower reserve limits, mean that the BES system is able to charge until the upper limit and discharge until the lower reserve limit of the available capacity. Such limits help maintaining the lifespan of the corresponding battery [136]. Since the SOC is at the lower level, the BES system is not able to supply any energy to the household (black line); hence, its charge/discharge profile (red line) remains zero until 8am. From 8am onwards, when the PV generation increases (magenta line), the BES system starts charging (i.e., positive values) with a power rate equal to the excess PV generation (i.e., PV generation minus the demand). While charging, the SOC is increasing as more energy is stored in the battery and, for this case, reaches full SOC (i.e., 90% due to the upper reserve) around 2pm. Once the SOC reaches the maximum, the charge/discharge profile goes to zero and remains there until the time where the PV system is not generating anymore. Once the PV generation is equal to zero (around 8pm), the BES system starts discharging (i.e., positive values) with a power rate equal to the household demand. While discharging, it can be seen that the SOC is decreasing until the next day.

On the second day, the BES system is still supplying the household demand during the early hours. Since the total energy stored in the BES is higher than the energy demand of the corresponding household, the battery starts charging with some energy already stored (i.e., around 25% of SOC). This, however, forces the battery to reach full SOC even earlier in the following day. Indeed, as demonstrated in Figure 3-6, a full SOC is achieved around 12pm on the second day, which is 2 hours earlier than the first day.

3.3.1.3 Limitations

The adoption of residential-scale BES systems using the "normal operation" mode as described above suffers of the following two important limitations:

- **BES systems might not adequately discharge.** Due to the uncertainty of household demand each day, the normal operation modes might not be able to fully discharge the battery overnight. This in turn limits the ability of the battery to fully utilise its storage capacity the following day. This issue becomes even more critical in cases where the household demand is significantly low.
- **BES systems reach full SOC very early.** Due to the fact that the normal operation modes cannot guarantee full discharge of the battery during the night, the battery might become full earlier the next day. From a DNO perspective, this operation might not provide significant benefits in terms of voltage and thermal issues since batteries might not be able to absorb excess PV generation (exports) during critical periods (around midday).

3.3.2 Advanced Operation Mode

This section presents the proposed "advanced operation" mode for residential-scale BES systems which is based on the common operating principles of commercial BES systems previously discussed in section 3.3.1 and, hence, still beneficial to customers. It overcomes the limitations discussed in the previous section by modifying the charging/discharging rates so as to minimise network impacts.

To overcome the limitations discussed in section 3.3.1.2, the proposed method defines specific times and final SOC for the charging and discharging periods in a way that is beneficial to both customers and the LV network (i.e., DNO). By knowing when a charging/discharging period starts and ends, it is possible to calculate the charging/discharging power rate that makes the BES system progressively charge/discharge to achieve the defined final SOC.

Furthermore, to play an active role in the management of voltages during daylight, the proposed advanced operation mode also increases the charging power rate when the voltage at the connection point rises above the statutory limit. In addition, to ensure the demand is always met, the discharging rate is increased when needed. It is important to note that the performance of the proposed advanced operation mode might be influenced by the size of the installed BES systems, as the ability to manage issues depends on their storage capability.

The control logic of the proposed advanced operation mode, which is based only on one cycle per day (one charging and one discharging period), is detailed below and the flowchart of the algorithm is given in Figure 3-8.

1. <u>Defining Charging and Discharging Periods and Final SOCs</u>

The lengths of the charging (T_C, in hours) and discharging ($24 - T_C$) periods need to be defined as well as the corresponding final states of charge, SOC^{C}_{final} and SOC^{D}_{final}, respectively. Although the latter two can adopt diverse values, it is suggested to have a fully charged battery at the end of the charging period and an empty battery at the end of the discharging period (in both cases taking account of the reserve limits). The former (full battery) allows collecting the maximum possible "green" energy from the PV system and, therefore, increasing the customer's self-consumption (i.e., reduced grid dependence) while the latter (empty battery) ensures that adequate room will be available in the battery to charge the following day. In addition, the charging and discharging periods should be defined based on the time at which the peak sun irradiance is occurring, t_{peak}. Figure 3-7 illustrates this considering the local seasonal irradiance profile.

a) **Charging Period:** The total charging period (T_C) is defined based on the DNO and customer requirements and should always be equal or smaller than the daylight period (total time between sunrise and sunset). Once T_C is defined, the time where the charging period starts (t_C^{start}) and ends (t_C^{end}) is set to be $t_{peak} - \frac{T_C}{2}$ and $t_{peak} + \frac{T_C}{2}$, respectively. This setting, as shown in Figure 3-7, allows having a charging period which is symmetrical to the peak irradiance time, t_{peak}.

b) **Discharging Period:** Once the charging period is defined, the discharging period is defined as the time between the end of the charging period until the start of the next charging period (i.e., next day).

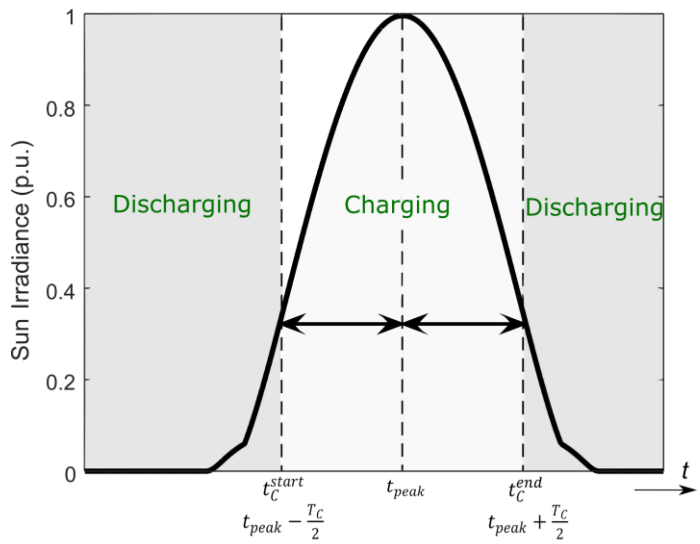


Figure 3-7 Charging and discharging period definition

2. <u>Charging and Discharging Power Rates</u>

The controller progressively charges or discharges the BES system based on a power rate proportional to the amount of energy required to charge or discharge so the desired final SOC (SOC_{final}^C or SOC_{final}^D) can be achieved.

The following process which is also graphically demonstrated with the flowchart given in Figure 3-8, is performed locally at each BES system for each instant t.

Charging power rate. The BES system is restricted to charge only from the excess of PV generation ($P_t^{PV\_excess}$) at the corresponding instant t, calculated using (3.15). $P_t^{PV\_excess}$ is defined as the difference between PV generation (P_t^{PV}) and the household demand (P_t^{demand}). The latter two are based on local measurements (i.e., generation and demand of the household) which are taken every instant t.

$$P_t^{PV\_excess} = P_t^{PV} - P_t^{demand} \tag{3.15}$$

If the $P_t^{PV\_excess}$ is equal or less than zero (i.e., demand is higher than generation) then the charging power rate is set to zero, as there is no excess of PV generation to charge from. If the $P_t^{PV\_excess}$ is higher than zero, then the charging power rate P_{t+1}^C is calculated using (3.16) which is subject to the restriction in (3.17), where SOC_t is the SOC at instant t and $BES_{KWh}^{capacity}$ is the system's capacity in kWh.

$$P_{t+1}^C = \begin{cases} 0 & , if\ P_t^{PV_{excess}} \leq 0 \\ \dfrac{\left(SOC_{final}^c - SOC_t\right) \times BES_{KWh}^{capacity}}{\left(t_{peak} + \dfrac{T_C}{2}\right) - t} & , if P_t^{PV_{excess}} > 0 \end{cases} \tag{3.16}$$

$$P_{t+1}^C \in [0, P_t^{PV_{excess}}] \tag{3.17}$$

Discharging power rate. When in the discharging period, the discharging power rate for the next instant (P_{t+1}^D) is calculated using (3.18).

$$P_{t+1}^D = \frac{(SOC_t - SOC_{final}^D) \times BES_{KWh}^{capacity}}{\left(t_{peak} - \dfrac{T_C}{2}\right) - t} \tag{3.18}$$

It is important to highlight that if the household demand (P_t^{demand}) is larger than the discharging power rate (P_{t+1}^D), calculated in (3.18), then the P_{t+1}^D is automatically set to be equal to the P_t^{demand} so that the BES system will always follow the local demand (i.e., self-consumption). This is true provided the battery has enough stored energy in the early morning.

3. Voltage Control Feature

In order to directly manage voltage issues, a voltage control feature is considered in the charging period of the proposed advanced operation mode. This feature is triggered once the household voltage, V_t (measured at each instant), reaches the statutory limit (V_{limit}^{upper}). When this happens, the net household active power is recorded and is considered to be the household's active power export limit ($P_t^{exp\_lim}$) that results to a voltage close to the statutory limit. This limit is then updated for every subsequent instant ($P_{t+1}^{exp\_lim}$) using (3.19); where a corresponds to a threshold (e.g., 1.0 corresponds to a 100% of the statutory voltage limit). This equation smoothens the values of the limits (given the changing nature of demand and generation as well as the effects of other customers on voltages) and allows tuning the limit towards more conservative values (lower a) if needed.

$$P_{t+1}^{exp\_lim} = \frac{(a \times V_{limit}^{upper}) \times P_t^{exp\_lim}}{V_t} \tag{3.19}$$

For as long as the voltage control feature is on, the charging power rate P_{t+1}^{C} is updated accordingly in order to satisfy the household export limit $P_{t+1}^{exp\_lim}$ and, therefore, keep the voltage close to the statutory limit. To perform the update, first, the household's export power ($P_{t+1}^{house\_exp}$) resulting from the P_{t+1}^{C} in (3.16) is calculated using (3.20). It is important to highlight that, in this case, a persistent forecasting is assumed for the household demand and generation. This means that, for this equation only, the excess of PV generation at instant *t* ($P_t^{PV\_excess}$) is assumed to be the same for the next instant *t+1* ($P_{t+1}^{PV\_excess}$).

$$P_{t+1}^{house\_exp} = P_{t+1}^{PV\_excess} - P_{t+1}^{C} \tag{3.20}$$

If the $P_{t+1}^{house\_exp}$ is found to be larger than the $P_{t+1}^{exp\_lim}$, it means that the charging power rate, calculated using (3.16) needs to increase (to reduce the household's export power) in order to satisfy the export power limit. The updated P_{t+1}^{C} is then calculated using (3.21).

$$P_{t+1}^{C} = P_{t+1}^{PV\_excess} - P_{t+1}^{exp\_lim}, \qquad if\ P_{t+1}^{house\_exp} > P_{t+1}^{exp\_lim} \tag{3.21}$$

If, however, the $P_{t+1}^{house\_exp}$ is lower than or equal to the export limit ($P_{t+1}^{exp\_lim}$), the charging power rate is not updated, i.e., remains as calculated in (3.16). The voltage control feature is deactivated once the charging period ends.

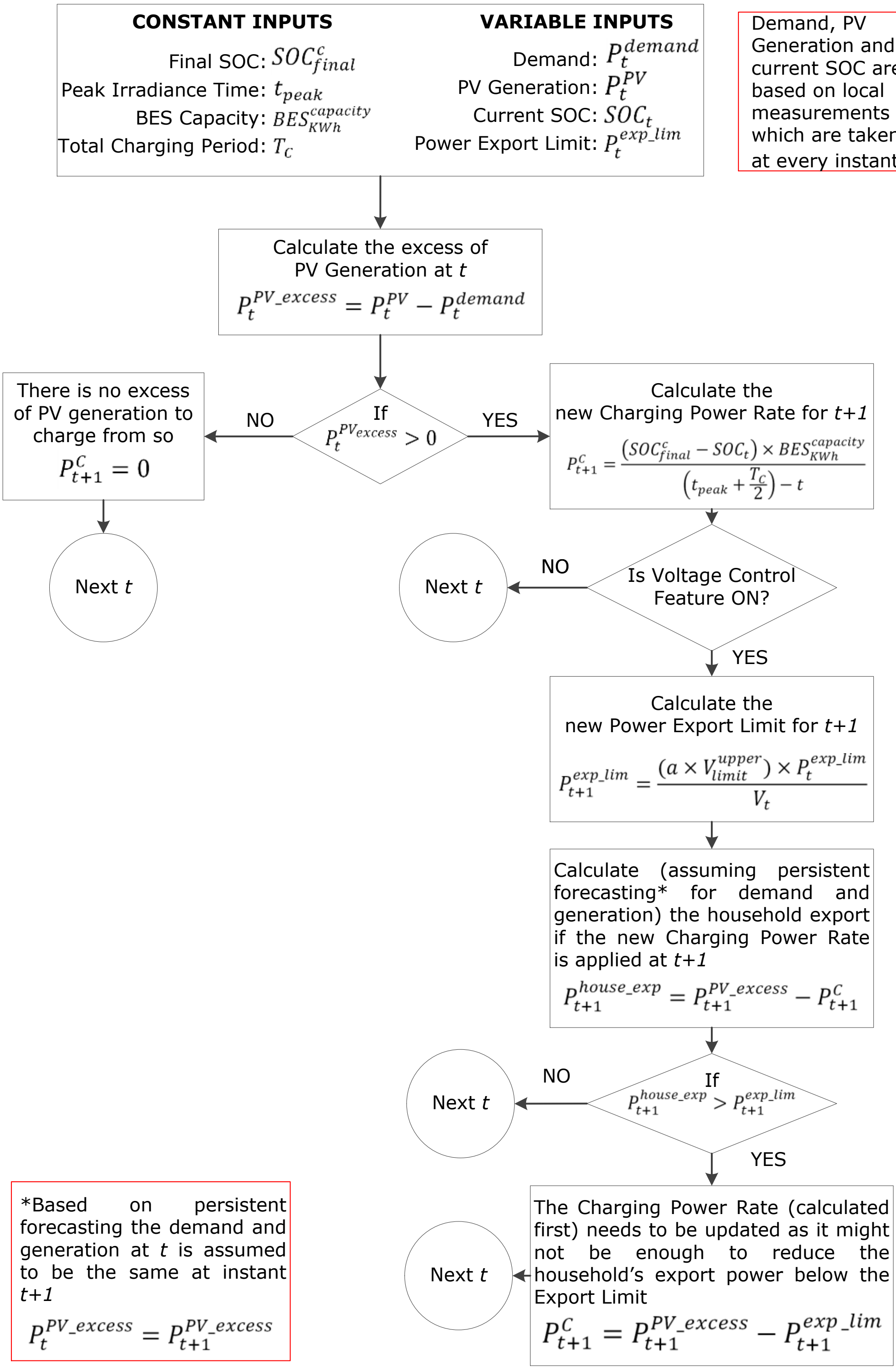


Figure 3-8 Advanced operation mode flowchart

3.3.2.1 Illustrative Example

Figure 3-9 demonstrates the behaviour of the proposed advanced operation of a BES system using the same example as in section 3.3.1.2 (i.e., household with 3kWp PV system and a 3.3kWp 10kWh BES system).

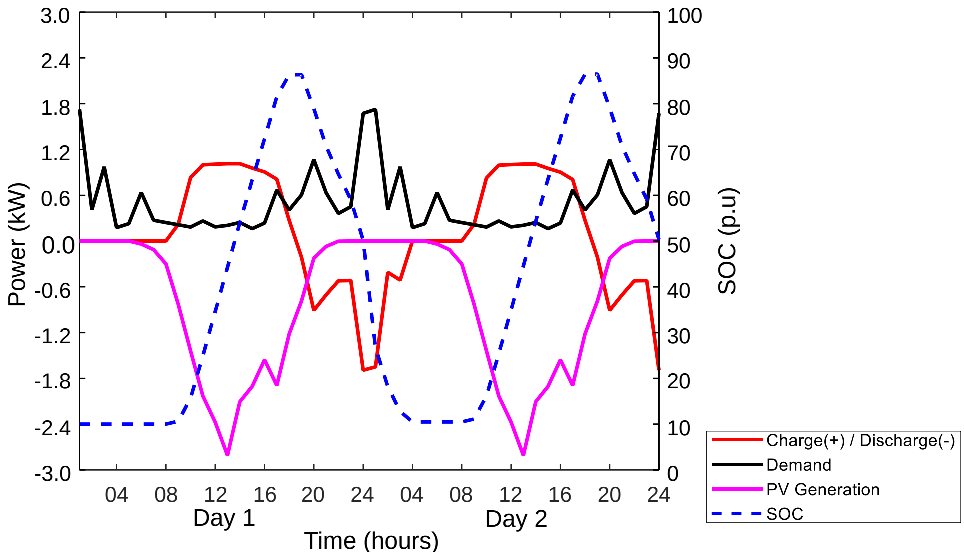


Figure 3-9 Illustrative example of advanced operation mode

As also described previously (3.3.1.2), the first day of the example is assumed to be the first day where the BES system is installed at the household and, therefore, it is considered to be empty (i.e., SOC at the lowest point, 10%). Considering this, the BES system is not able to supply any energy to the household (black line); hence, its charge/discharge profile (red line) remains zero until 8am when the discharging period finishes. From 8am onwards, when the charging period begins (i.e., here assumed to be 8am to 6pm), the BES system starts to progressively charge with a power rate specified by the proposed advanced mode. The proposed progressive power rate provides a solution to the limitation of the normal operation mode where the BES systems become full very early during the day. As observed in Figure 3-9, the SOC is increasing linearly as more energy is stored in the battery and it can be seen that the proposed advanced mode manages to reach full SOC at the assumed specified end of the charging period (i.e., here assumed to be 6pm).

It is also important to highlight that in the case where voltage (at the household connection point) increases above 1.1p.u., the proposed advanced mode will increase the charging power rate (as detailed in section 3.3.2) in order to bring the voltage below 1.1p.u. In such case, SOC is expected to increase faster as additional energy is required to be stored. Considering the nature of the progressive charging (linear increment of SOC until the end of the specified charging period), when voltage issues occur during midday (peak sun radiation), SOC will always be close to 50%. Hence almost 50% of the storage headroom will always be available to use in order to manage the corresponding voltage issues.

Once the BES system goes into the discharging mode (i.e., 6pm to 8am for this example) the battery is discharging with a power rate equal to the household demand. As detailed in section 3.3.2, the proposed advanced operation mode (when in discharging period) will progressively discharge with a power rate specified by the controller. However, if the household demand is higher than the specified discharging rate, it automatically follows the demand as indeed happens in this case. For example, at 6pm (beginning of example's discharging period) the discharging power rate, calculated by the controller, is close to 0.7kW (i.e., 10kWh/14hrs) which is lower than the household demand; hence, the BES system is discharging with a power equal to the demand. For this particular case, it is shown that the BES system is becoming empty at an earlier time (i.e., 4am) than the specified one (i.e., 8am – end of discharging period) due to the high discharging power rates caused by following the household demand.

It is also important to mention that in cases where household demand is significantly lower than the stored energy, the progressive discharge of the proposed advanced operation mode guarantees that the BES system will fully discharge by the start of the charging period. This, as a consequence, overcomes the drawbacks of the normal operation mode and allows the full utilisation of the storage capacity in every charging period.

More importantly, Figure 3-9 shows that the same expected performance is also noticed in the following day providing a very good utilisation of the BES system, compared to the performance when using the normal operation.

3.4 LV OLTC-fitted Transformers

This section provides the details of the scalable and adaptive OLTC control logic proposed in this Thesis which aims at managing contrasting voltages issues (rise and drop). Considering the gaps identified in the current literature, the proposed method allows the automatic update of the voltage target (at the busbar) according to network conditions while using limited network observability (only from critical remote monitoring points). Crucially, this provides the significant benefit of being easy to adapt to network changes (i.e., additional PV system installations or loads) without the need of reconfiguring OLTC settings.

3.4.1 Architecture

Figure 3-10 shows a simplified schematic, demonstrating the control architecture of the proposed control scheme which considers metrology and communication units (MCUs) at critical points of LV feeders (e.g., middle or end). The MCUs collect and send the corresponding monitoring data (i.e., voltages) to the remote terminal unit (RTU) located at the secondary (i.e., MV/LV) distribution substation. The RTU is, in this case, the physical device in which any control logic is coded. Based on this logic, the RTU can then send to the OLTC controller a command to produce a busbar voltage (V^{target}) that ultimately alleviates any potential voltage issues.

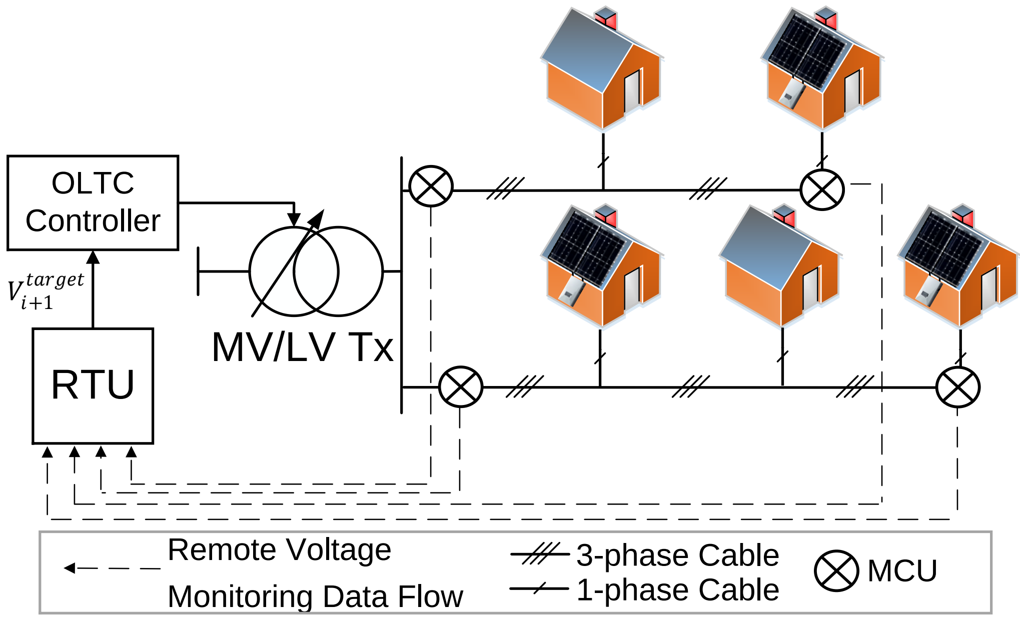


Figure 3-10 OLTC proposed control architecture

3.4.2 Control Logic

The control logic considers voltages at remote points to calculate the voltage at the busbar (V^{target}, to be sent to the OLTC controller) required to bring voltages along the feeders within the statutory limits.

At every control cycle (i), the minimum and maximum values (V_i^{min}, V_i^{max}) of all monitored line-to-neutral phase voltages (V_i^a, V_i^b, V_i^c) at the remote points of the feeders are found. Then, it is checked whether these two values are within the controller's safe zone as shown in Figure 3-11. The latter (i.e., the safe zone), considers a bandwidth (green area in Figure 3-11) which is defined as a percentage value above and below a reference voltage (V_{ref}). The reference voltage and safe zone are parameters that can be adjusted according to the DNO requirements. Thereafter, and as illustrated in Figure 3-11 (a), if both values V_i^{min} and V_i^{max} are within the safe zone, then no action is taken and the controller proceeds to the next control cycle. On the other hand, and as shown in Figure 3-11 (b), if any of the two values lies outside the safe zone, then their differences from the V_{ref} are calculated (ΔV_i^{min}, ΔV_i^{max}). The average of these voltage differences (ΔV_i^{mean}) is then used to calculate the new voltage target (V_{i+1}^{target}) as in (3.22).

$$V_{i+1}^{target} = V_i^{target} + \Delta V_i^{mean} \tag{3.22}$$

If the new voltage target is outside the statutory limits ($V_{limit}^{min}, V_{limit}^{max}$), then the corresponding value is set to its nearest limit. Furthermore, using (3.23), the expected values of the remote monitoring points are estimated with a simple –yet effective– linear expression. If these values are within the statutory limits, the new voltage target (V_{i+1}^{target}) is sent to the OLTC controller. Otherwise, the voltage target is not changed ($V_{i+1}^{target} = V_i^{target}$).

$$V_{estimation}^{monitored} = \frac{V_{i+1}^{target} \cdot V_i^{monitored}}{V_i^{target}} \tag{3.23}$$

The flowchart for the proposed control logic is given in Figure 3-12. It is important to highlight that due to the nature of the control logic (i.e., considering both highest and lowest voltages), the voltage target calculated will be influenced by the higher difference ($\Delta V_i^{min}, \Delta V_i^{max}$) and, therefore, the new voltage target is expected to maintain the monitored voltages within the statutory voltage limits. It is important to highlight that in case of simultaneous voltage rise and drop of same magnitude, the average voltage difference will be equal to zero and, therefore, the voltage target will not change.

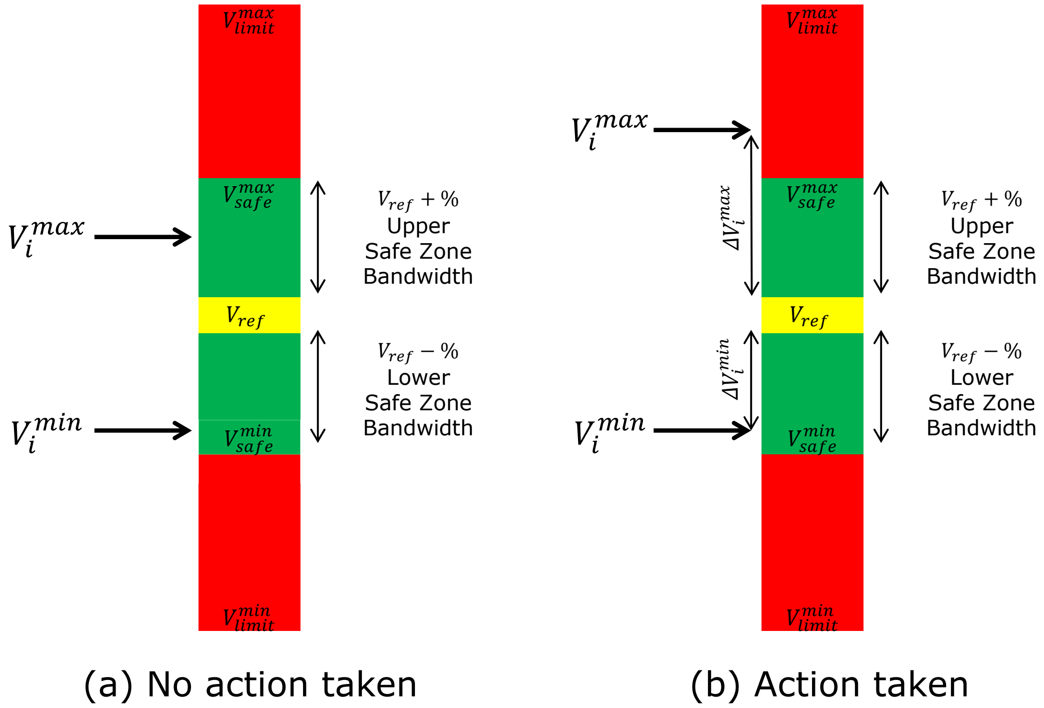


Figure 3-11 Controller example

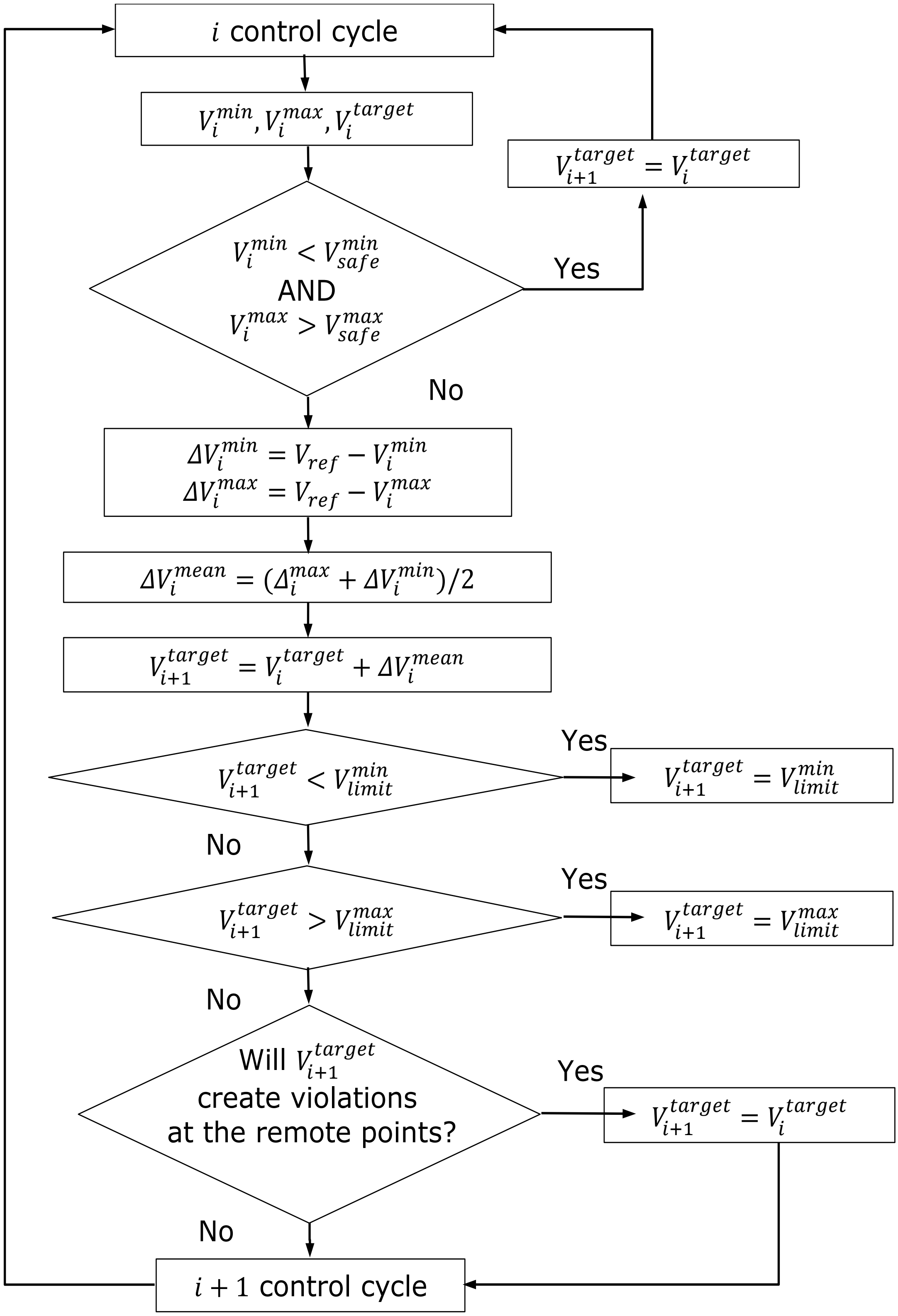


Figure 3-12 OLTC control logic

Chapter 4

Case Study Part 1: Modelling

4.1 Introduction

As previously mentioned in section 1.2.4, one of the main challenges associated with the corresponding research and also found to be one of the gaps in the literature is the lack of realistic modelling, including the use of high resolution time-series analyses of LV networks. To bridge this gap, detailed data of a real French LV network, smart meter data from 975 customers, and 3 real monitored PV generation profiles were facilitated by the industrial partner EDF R&D for the purposes of this Thesis. These data, which are detailed in this chapter, allow modelling real French LV networks to then perform realistic, high resolution (i.e., 1-min) time-series analyses.

4.2 Real French LV Network

A real French LV network, located in Paris[1], and operated by ERDF, is adopted as the test LV network to assess the performance of the active network management schemes proposed in this Thesis. According to the industrial partner (EDF R&D), the corresponding network is selected as it is considered to be a typical LV network in France. This allows understanding the extent to which the proposed active network management schemes can provide benefits in terms of voltage and thermal management.

The topology and main characteristics per feeder (i.e., single-phase customers and the total sum of the 3-ph cable length) are shown in Figure 4-1. The LV network consists of four feeders (each represented in a different colour) and a total of 162 domestic single-phase customers (blue dots). These feeders are supplied by a three-phase 400kVA single distribution (i.e., 20/0.41kV) transformer (black triangle).

[1]The exact geographical location of the network is not provided due to confidentiality aspects.

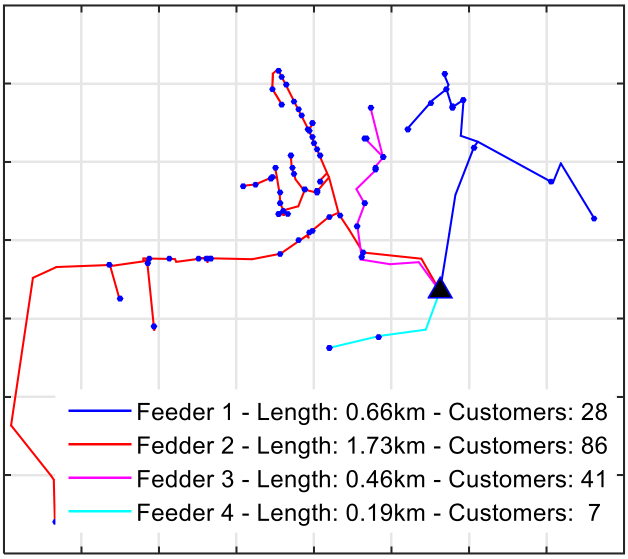


Figure 4-1 French LV network

4.2.1 Transformer

The transformer is equipped with an off-load tap changer having a range of +1/-1 (taps) with 2.5% per tap, i.e., 3 off-load tap positions in total. Assuming (and adopted in the analyses) that the voltage at the primary side of the MV/LV transformer is the nominal line-to-line voltage (i.e., 20kV), the busbar voltages corresponding to different off-load tap positions are shown in Table 4-1. According to the data provided, the off-load tap changer of the test LV network is set to tap position 2 which results on the nominal transformation of voltages (i.e., 20kV to 400V).

Table 4-1 Voltage regulation of the modelled LV off-load tap changer

Off-load Tap position	MV	LV		Vbase = 400V
	L-L (V)	L-L (V)	L-N (V)	V (p.u.)
1 (+2.5%)	20000	400	230.9	1
2	20000	410	236.7	1.025
3 (-2.5%)	20000	420.3	242.6	1.051

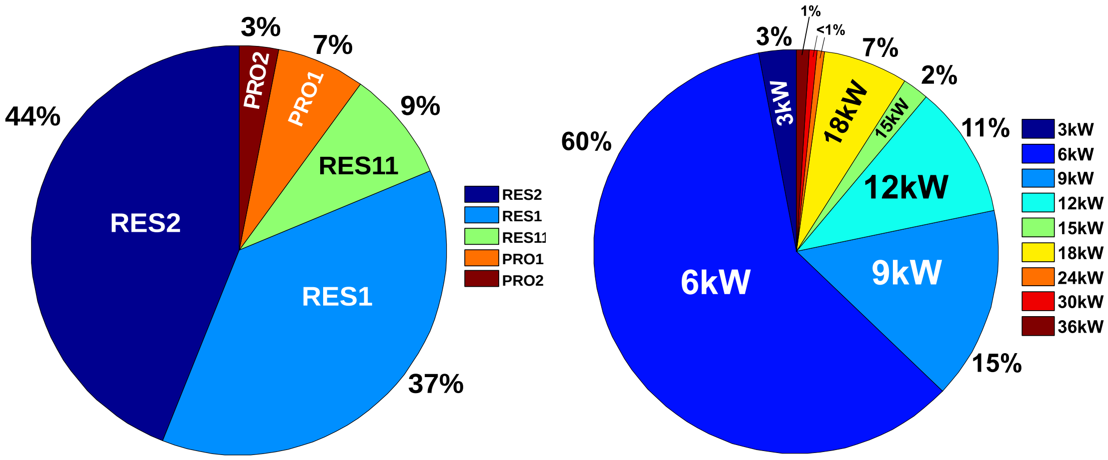
4.3 Real Smart Meter Data

Data recorded from 975 smart meters, of both residential and commercial customers, located in France were also provided in the form of .csv files. These files include information of the date, time and power of each of the customers with a 30-min resolution for the period of October 2013 to June 2014. The data were collected from different types of French customers, as shown in Table 4-2, with different subscribed powers ranging from 3 to 36kW. These data are used to realistically model the individual daily behaviour of LV customers.

Table 4-2 Types of customers in France

RES1 (Blue Residential Base)	Residential - Flat tariff - Power subscribed =< 6kVA
RES11 (Blue Residential Base)	Residential - Flat tariff - Power subscribed > 6kVA
RES2 (Blue Residential HPHC[2])	Residential - Time of use tariff
PRO1 (Blue Professional Base)	Professional - Flat tariff
PRO2 (Blue Professional HPHC)	Professional - Time of use tariff

Figure 4-2, shows the composition of the received data by type (Figure 4-2 (a)) and subscribed customer power (Figure 4-2 (b)). As shown in Figure 4-2 (a) the majority of the smart meter data is coming from RES2 (44%) and RES1 (37%) type of customers where the rest are from RES11 (9%), PRO1 (7%) and PRO2 (3%). It is important to highlight that 60% of the total smart meter data are customers with a 6kW subscribed power, 15% with 9kW and 11% with 12kW. The remaining 14% of data is divided to 36, 30, 24, 18, 15 and 3kW subscribed customers.

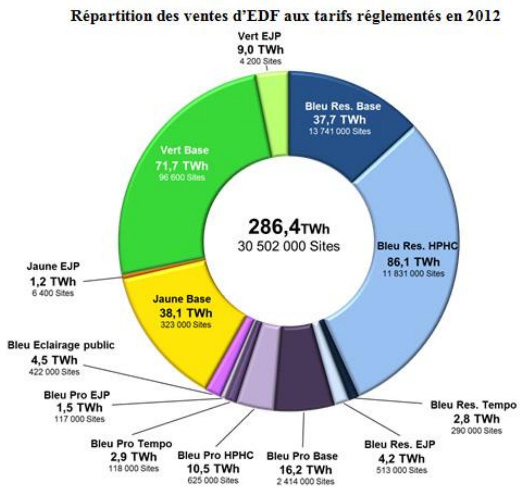


(a) (b)

Figure 4-2 Composition of Smart Data by (a) Type and (c) Subscribed power

According to the Regulatory Commission of Energy (CRE - Commission de régulation de l'énergie) [140], the distribution of EDF's customers among different types is as shown in Figure 4-3. Therefore, considering only the Blue Residential and Professional types (93% of the total connections in France) the proportions of RES1+RES11, RES2, PRO1, and PRO2 types are 48, 41.4, 8.4, and 2.1%, respectively. These proportions highlight that the smart data received represent a realistic sample of the real distribution of customers in France.

[2] FR: Heures Pleines / Heures Creuses – EN: Peak hours/ Off-Peak hours



Type	Customers
RES1+RES11	13.7 million
RES2	11.8 million
PRO1	2.4 million
PRO2	0.6 million

Figure 4-3 Distribution of EDF's customers among the different types [140]

4.3.1 Construction of Domestic Load Profiles

The smart meter data are used to realistically model the load behaviour in the simulations performed in this Thesis. The power information was extracted and daily half-hourly load profiles were created for all types of customers, subscribed power, month and type of day. An example of how load profiles were created is shown in Figure 4-4 for a RES1 - 3kW customer in October. The recorded load profile (3rd column - Watts) of a specific weekday (1st column - 1st October 2013) for hours 00:00 to 23:30 (2nd column - 48 points) constitutes a single load profile to be added in the October's pool of weekday load profiles.

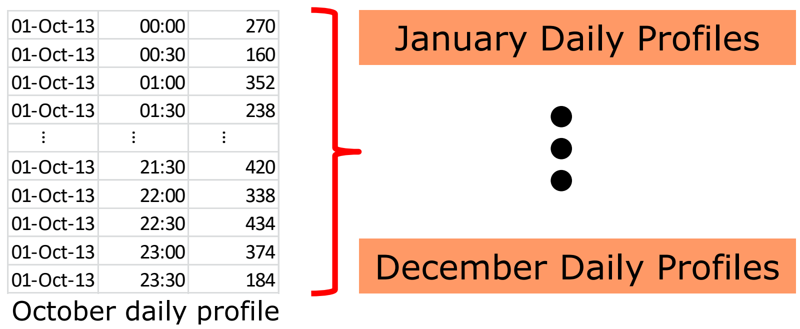


Figure 4-4 Load Profile Creation Example

A total of 179,850 load profiles were created and categorised in folders based on the type of customer. Each type of customer was categorised in sub-folders for each subscribed power including subcategories for the 12 different months. Each month contains 9 categories/folders (one for each available subscribed power) where each subscribed power folder contains a pool of daily load profiles categorised by the type of day (i.e., weekday, weekend). Figure 4-5 shows how the data were categorised in folders to create pools of load profiles to then use and realistically model the load behaviour in the analyses.

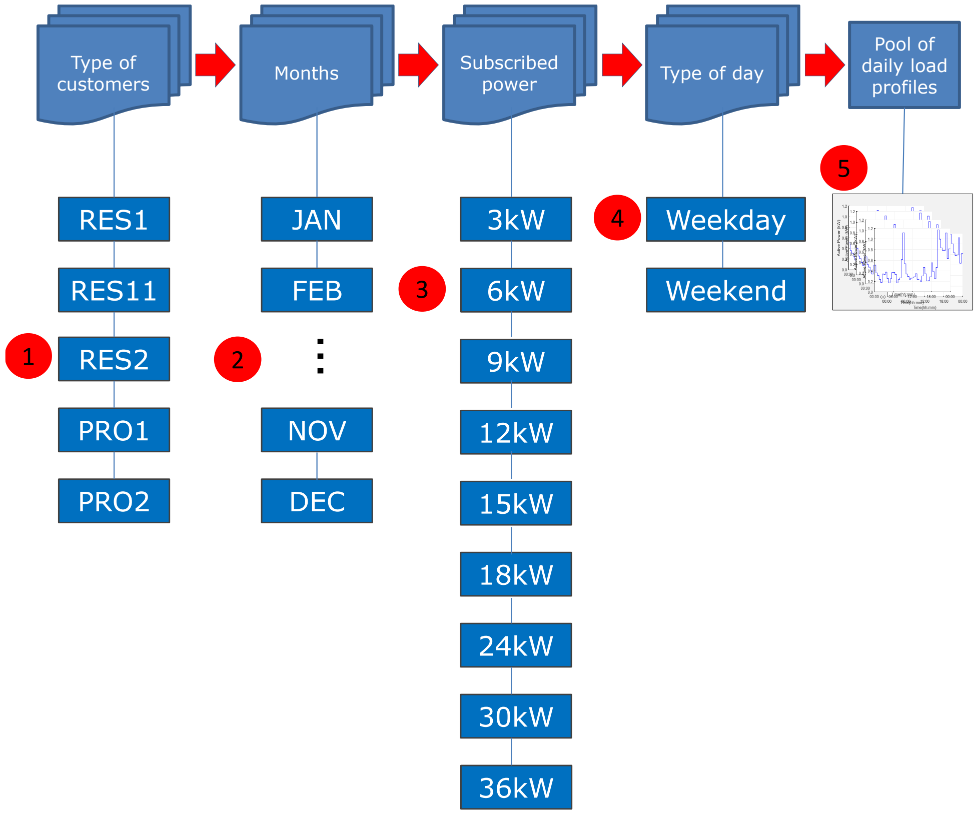


Figure 4-5 Smart meter data categorisation

Since in this Thesis all analyses consider 1-min time-series simulations, it is important to highlight that the 30-min resolution (48 points) load profiles are converted to 1-min resolution (1440 points) as shown in Figure 4-6. Each point within a segment of 30 minutes in Figure 4-6 (b) has the same value that corresponds to the specific half-hourly value in Figure 4-6 (a).

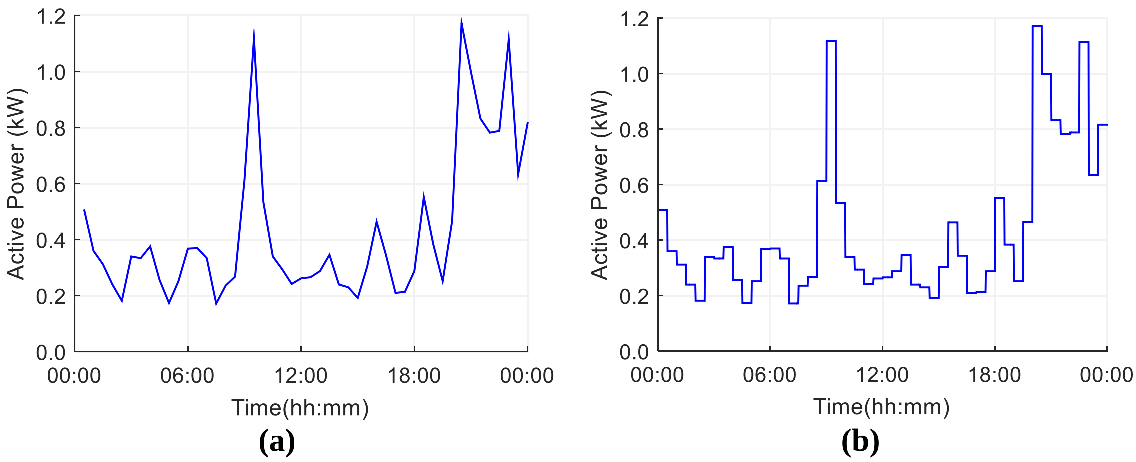


Figure 4-6 Conversion of a load profile from (a) 30-min to (b) 1-min resolution

4.3.2 Allocation of Domestic Load Profiles

The available information regarding the loads (i.e., customers) in the real French LV network is limited only to the subscribed power of customers connected in each feeder – in this case, 3, 6, 9 and 12kW. Therefore, real French domestic load profiles, created from smart meter data as described in the previous section 4.3.1, are used for the analyses.

As previously mentioned, according to the French Regulatory Commission of Energy [140], the number of RES1+RES11, RES2, PRO1, and PRO2 connections in France are 13.7, 11.8, 2.4, and 0.6 million, respectively. To make the analyses more realistic, the random distribution of domestic loads in the network considers the percentages of different types of customers using the information of the number of connections for each type as shown in Table 4-3. It is important to highlight that the share of customers between RES1 and RES11 was assumed to be the same share as in the smart meter dataset.

Table 4-3 Number of connections for each type of customer [140]

Type	Customer Connections
RES1	11.1 million
RES11	2.6 million
RES2	11.8 million
PRO1	2.4 million
PRO2	0.6 million

Therefore, the type of each load in the test LV network is assigned based on the subscribed power and the total number of connections per type. Once the type of customer is assigned, a load profile is also assigned to that customer model using a random profile from the pool of load profiles (created using the smart meter data). The procedure can be described with the following example.

Assuming a customer of a 6kW subscribed power; its type could be RES1, RES2, PRO1 or PRO2. Considering the information shown in Table 4-3 a customer type is randomly selected considering the statistical probability of being a specific type as defined by (4.1), (4.2), (4.3) and (4.4).

$$P_{RES1} = {}^{11.1}/_{(11.1 + 11.8 + 2.4 + 0.6)} = 42.9\% \tag{4.1}$$

$$P_{RES2} = {}^{11.8}/_{(11.1 + 11.8 + 2.4 + 0.6)} = 45.6\% \tag{4.2}$$

$$P_{PRO1} = {}^{2.4}/_{(11.1 + 11.8 + 2.4 + 0.6)} = 9.3\% \tag{4.3}$$

$$P_{PRO2} = {}^{0.6}/_{(11.1 + 11.8 + 2.4 + 0.6)} = 2.3\% \tag{4.4}$$

Once the customer's type is selected (based on the statistical probabilities above), the procedure to select a load profile for the corresponding customer model is demonstrated in Figure 4-5 and described below:

1. First the folder containing all the load profiles for the assigned type of customer is selected. For demonstration purposes it is assumed that a RES2 type of customer is assigned (using on the statistical probabilities above).

2. Then, within the customer type folder, the folder containing all the created load profiles for the month required to perform the analysis is selected.

3. Within the selected month folder, the folder containing all the load profiles for the specific subscribed customer power is selected. For demonstration purposes the subscribed customer power is assumed to be 6kW.

4. Within the subscribed customer power, the folder containing the load profiles for the type of day that the analysis needs to be performed for, is selected.

5. Finally, a random daily load profile is selected from the pool of profiles contained in the last selected folder. This profile is used to model the corresponding customer's 24-hr power demand.

4.4 Realistic PV Generation Profiles

PV generation profiles are modelled using an available tool developed by the University of Loughborough, Centre for Renewable Energy Systems Technology (CREST) [141]. In the CREST tool, once the day and the configuration information of the installed PV panel (e.g., location, efficiency, area, etc.) are determined, 1-min resolution generation and net radiation profiles can be produced. Both of the profiles correspond to the outdoor irradiance on the chosen day of the year.

Using the aforementioned tool [141], considering PV panels with tilt angle of 35°, azimuth of 0° (south facing), and Paris as the geographical location, it was possible to extract the daily radiation profile of the middle day of each month of the year and generate 100 daily sky brightness/cloudiness indexes (B_{index}) for each month. Using these data, another tool is created to randomly generate sunny PV profiles for each month. The new tool, using equation (4.5), essentially replicates the CREST tool procedure to generate the sunniest PV profiles for each month. Figure 4-7 (a) and (b), shows 4 random daily PV generation profiles (3 and 6kWp systems) for January (winter) and June (summer), respectively.

$$PV_{profile} = \eta_{panel} \times \eta_{inverter} \times A_{panel} \times H_{month} \times B_{index} \tag{4.5}$$

where η_{panel} and $\eta_{inverter}$ are the panel and inverter efficiencies, respectively. The A_{panel} is the area of the panel and the H_{month} is the irradiance profile of the corresponding month.

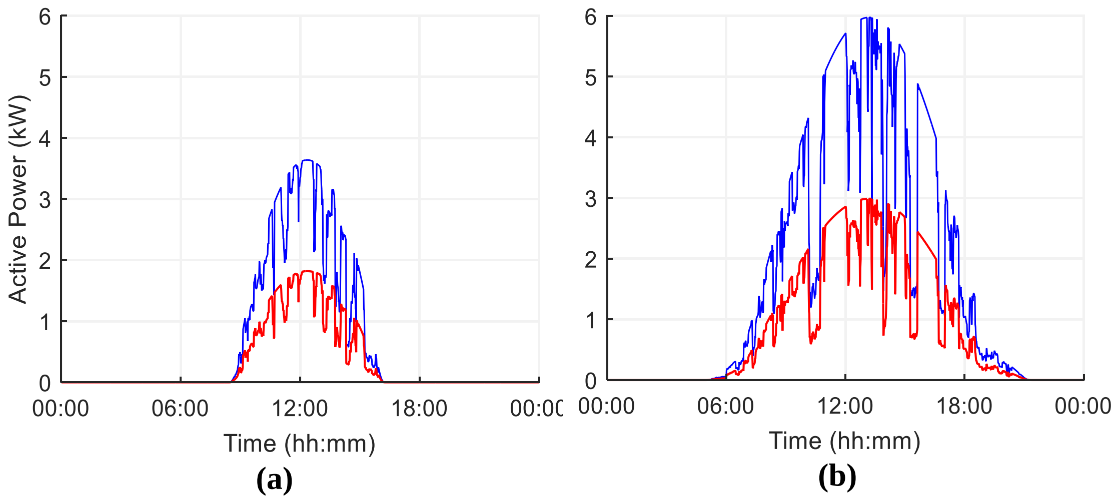


Figure 4-7 Daily PV profiles of 3 and 6kWp systems (a) January and (b) June

4.4.1 Comparison with Real French PV Generation Profiles

Three real monitored PV generation profiles, from the region of Paris, were also provided by the industrial partner (EDF R&D) for the purposes of this Thesis. These profiles have a 10-sec resolution and were monitored during the days 9th, 11th and 14th of April 2014. In order to understand how realistic are the PV profiles created with the CREST tool (1-min resolution) the real PV profiles were converted to 1-min resolution, as shown in Figure 4-8. The assessment of two basic metrics (capacity factor and %difference to minute by minute power amplitude) showed that the modelled PV profiles, using the CREST tool, can be considered realistic. The comparison is described in the following sections.

4.4.1.1 Capacity Factor

Three random sunny PV generation profiles in April (Figure 4-8 - blue profiles) were created using the CREST tool to be compared with the real PV profiles (Figure 4-8 - red profiles). The daily capacity factor of the real PV profiles found to be 27%, 23% and 27%, respectively and 26%, 28%, and 27% for the modelled PV profiles, respectively. As shown in Figure 4-8, the results highlight that both profiles real and modelled have almost the same capacity factor.

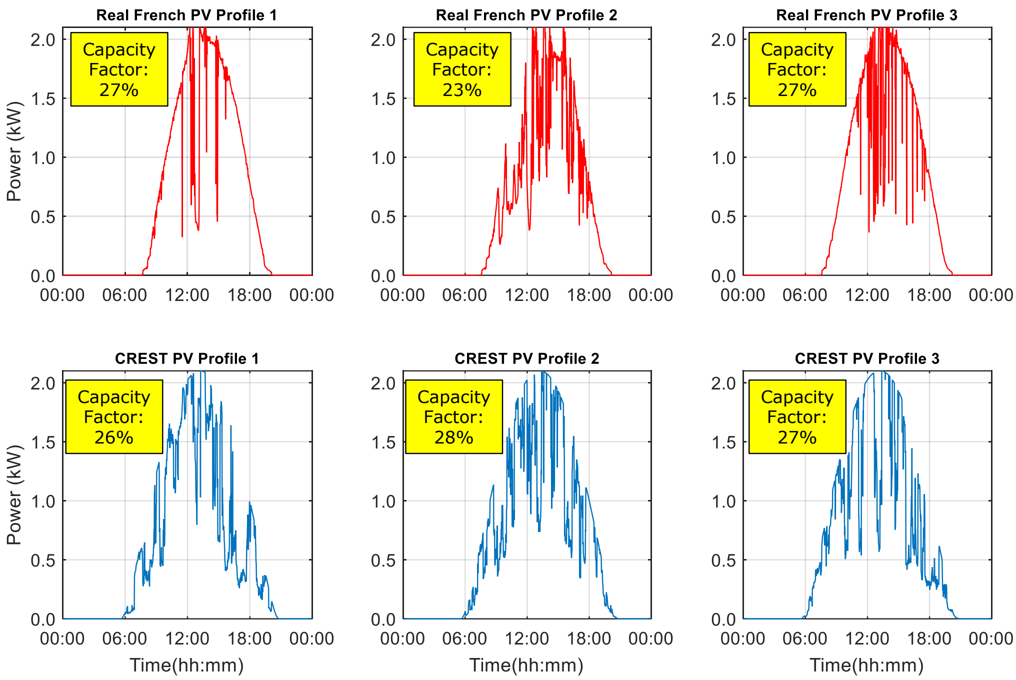


Figure 4-8 Daily Capacity Factor for Real and Modelled PV Profiles

4.4.1.2 Power Amplitude

The same profiles were analysed to calculate the minute by minute percentage difference of power amplitude during the hours of sunshine (08:30 to 20:00). Figure 4-9, shows the percentage difference (%difference) of power amplitude for each of the PV profiles (real and modelled). As it can be seen, during real conditions, power output can vary up to 125% from minute to minute. These high variations usually appear during the midday where the solar irradiance is high. Therefore, the amplitude can change rapidly from minute to minute due to the sky clearness effect (clouds passing through). Almost the same variations are noticed with the modelled PV profiles, however, the maximum variation of power amplitude is lower than the real PV profiles by 25%. Therefore, the modelled profiles can be considered as realistic and are used for the analyses.

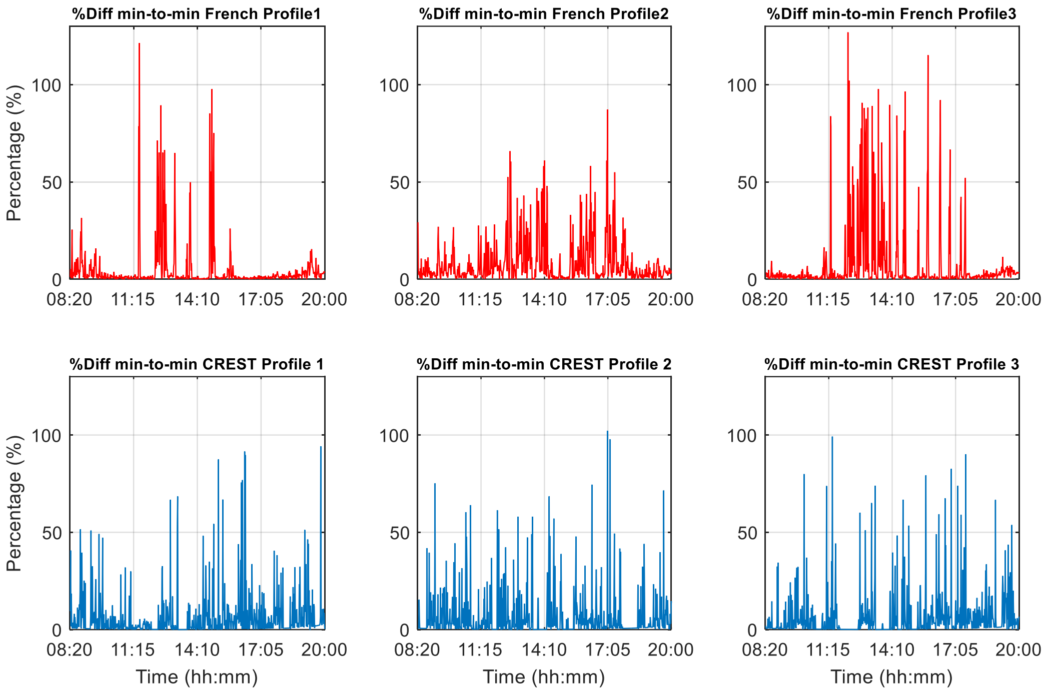


Figure 4-9 Minute to Minute %Difference of PV Power Amplitude

4.4.2 Allocation of Residential-scale PV Systems and Generation Profiles

A PV system allocation is adopted considering uneven penetrations per feeder and multiple installed capacities. This allows having feeders with higher PV penetration than others, resulting in more realistic and challenging scenarios (i.e., one feeder with higher voltages than other). This proposed PV allocation approach, which was endorsed by the industrial partner EDF R&D, is considered to realistically represent the current and future trend of residential-scale PV system installations in France.

Selected individual customers in the network are allocated PV systems with capacities based on their subscribed power as described below:

1. Customers with subscribed power of 3-36kW are allocated up to a maximum of 2 basic PV systems (a basic PV system is considered to have an installed capacity of 3kW).

2. Customers with subscribed power of >36kW are allocated with 1 basic PV system per 12kW of subscribed power.

Considering the above rules, the following definitions is considered to understand the concept of PV penetration (PV%):

Maximum Potential PV Hosting Capacity (MPHC): The maximum potential PV hosting capacity is the one resulting from having all customers with the maximum possible PV installed capacities (worst case scenario). In this case, all customers with a subscribed power 3-36kWp are allocated 2 basic PV systems and customers with a >36kWp subscribed power are allocated with 1 basic PV system per 12kW of subscribed power. Hence, the PV penetration (PV%) corresponding to a given installed capacity is calculated as the percentage of the MPHC.

Depending on the investigated PV penetration (PV%), PV systems are randomly allocated in the network until the corresponding fraction of MPHC in the network is reached. This is done having as a constraint the maximum PV capacity per customer as specified above.

4.4.2.1 Specifications of PV Inverters

The studies performed in this report consider the installation of PV inverters which are commonly used in residential-scale PV installations in the UK, France, and Europe [73]. The basic characteristics and specifications of the modelled inverters are given in Table 4-4:

Table 4-4 Modelled PV Inverter - Basic specifications

OUTPUT	
Apparent Power (S)	3/6/12 kVA
Active Power (P)	3/6/12 kWp
Reactive Power (Q)	0.9(leading) to 0.9(lagging)
CONTROL FUNCTIONS	
Volt-Var Control	Q(V) curve, up to 6 point curve
Volt-Watt Control	P(V) curve, up to 6 point curve
Active power limit	Limit of generation up to a % of the Pmax
COMMUNICATION INTERFACES	
WiFi	2-way communication
Radio Ripple Control Receiver (RRCR)	2-way communication
Local Area Network (LAN) via Ethernet	2-way communication

4.5 Monte Carlo Methodology

To cater for the uncertainties related to household demand as well as PV generation and location, the Monte Carlo methodology developed in [15] is adapted and used in this Thesis to assess the performance of the proposed control schemes. The main steps for a single simulation, given a specific network and PV penetration level, are described below and summarised in Figure 4-10.

1. The type of customers is selected based on their subscribed power and the calculated probability of each customer type as described in section 4.3.2.

2. For each customer, a random daily load profile is selected from the pool of load profiles corresponding to the customer's selected day/season, type, subscribed power and type of day.

3. Depending on the PV penetration level (PV%) PV systems are randomly allocated in the network based on the procedure described in section 4.4.2.

4. PV generation profiles are generated considering the season and the PV system capacity.

    a. Unbalanced, high resolution, time-series, three-phase four-wire power flows over a 24-hour period are carried out considering business as usual (BAU) scenario (without active management control). Simulation results are collected (voltage, current, power, etc.).

    b. Unbalanced, high resolution, time-series, three-phase four-wire power flows over a 24-hour period are carried out considering a given active network management scheme. Simulation results are collected (voltage, current, power, etc.).

The process described above is repeated one hundred times for each investigated PV penetration level. This number, as suggested and proved in [15], provides a trade-off between computational time and accuracy of the results. This allows to capture the stochastic nature of the LV network as the power flow analysis (voltage, current, power, etc.) from each daily simulation will be influenced differently; according to the load profiles, the location and size of the PV systems. The corresponding daily results (voltage, current, power, etc.) are stored for every single simulation. After a complete Monte Carlo analysis (i.e., 100 simulations of each investigated PV penetration level), the results from all the daily time-series simulations are analysed to assess the performance of the proposed control schemes using specific metrics (detailed in the following sections).

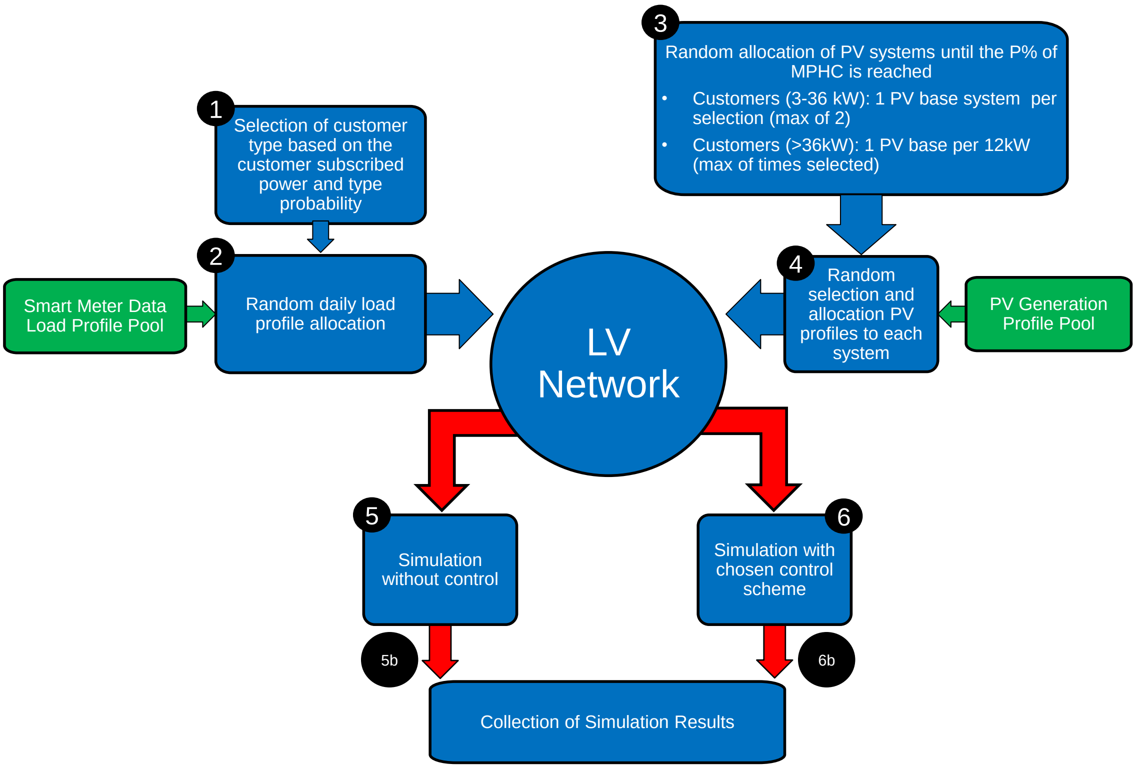


Figure 4-10 Monte Carlo Methodology

4.6 Performance Metrics

To quantify the technical impacts caused by different penetrations of residential-scale PV systems and also assess the performance of the proposed control schemes presented in Chapter 3, several performance metrics are adopted for the simulation analyses. This section, presents the metrics adopted in all simulation analyses regardless the case study (following chapters). Different case-specific metrics that might be required to certain specific control schemes are detailed in the corresponding chapters.

4.6.1 Voltage Issues

To understand the impacts of the residential-scale PV systems in terms of the voltage performance, the number of customers with voltage issues is calculated in each simulation.

Number of customers with voltage issues: This metric takes the voltage profile calculated for each customer connection point from the power flow simulation to then check if the European Standard EN 50160 [142], adopting the French statutory voltage limits (i.e., +/- 10% of nominal), is satisfied. If the customer's voltage does not comply with the standard, then this costumer is considered to have a voltage issue. Thus, the total number of EN 50160 non-compliant customers in the network is calculated.

The EN 50160 [142] indicates that the nominal voltage (U_n) in LV networks is 230 V (between phases and neutral) and:

"Under normal operating conditions, excluding situations arising from faults or voltages interruptions,

- *During each period of one week 95% of the 10 min mean rms values of the supply voltage shall be within the range U_n +/- 10%.*
- *All 10-minute mean rms values of the supply voltage shall be within the range of U_n +10% / -15%." [142].*

Since the time-series load and PV generation profiles have a resolution of 1 minute, the daily voltage profiles for each customer in the feeder are averaged in every 10 minutes to make the calculation according to EN 50160. Once the number of EN 50160 non-compliant customers is calculated for each simulation, the average and standard deviation are determined for each penetration level.

It is important to clarify that the compliance of customer connection points with the EN 50160 standard is used here for quantification purposes. Furthermore, the standard considers a week-long analysis instead of a single day. Consequently, the quantification of non-compliant customers as adopted in this work is a good metric but does not necessarily mean that the corresponding customers will actually experience voltage issues.

4.6.2 Thermal Issues

To understand the impacts of the residential-scale PV systems in the adequacy (capacity to supply demand) of LV networks, the utilization factor at the head of the feeders and transformer is calculated in each simulation.

<u>Utilisation level of feeder</u>: This metric assesses the utilisation level in the main segment of the feeder. This index is calculated as the 10 minute maximum current divided by the ampacity (cable rating) of the main segment of the feeder. To calculate the 10 minute maximum current, the current in the main feeder calculated from the simulation (1-min resolution) is averaged in every 10 minutes.

<u>Utilisation level of transformer</u>: This metric assesses the utilisation level of the substation transformer. This index is calculated as the 10 minute maximum power divided by the transformer capacity (i.e., 400 kVA). To calculate the 10 minute maximum power, the power at the transformer secondary side is calculated from the simulation (1-min resolution) is averaged in every 10 minutes.

The idea of these metrics is to show how the utilisation of the most important and expensive assets (i.e., feeder cables, transformer) of the network behaves with different PV penetration levels. These metrics allow visualising the assets' utilisation levels and therefore identifying if they increase above their maximum specified limits (i.e., thermal limits). It is important to highlight that increasing the utilisation level of the assets above their limits might lead to the increment of their insulation temperature above their operational limit which may result in damaging or accelerating the ageing of the corresponding assets. Crucially, these metrics help understanding how adopting the proposed control schemes can help keep the utilisation level of the assets always at or below their maximum limit.

4.6.3 Energy Metrics

<u>Total energy produced by residential-scale PV systems</u>: This metric allows evaluating how the proposed control approaches affect the PV generation (i.e., level of curtailment).

Network energy losses: This metric allows understanding how the proposed approaches affect the network's energy losses.

4.6.4 Control Actions

The total number of daily control actions required from all the proposed centralised control approaches is used as a metric to assess their performance. This metric is important as it allows understanding the extent to which the corresponding proposed control approaches are considered to be practical. Considering the decentralised control approaches, this metric is not quantified as control actions are performed locally and do not depend on any communication infrastructure.

In a centralised control approach, where communication infrastructure is required to perform the corresponding control actions, the fewer the daily control actions are, the better. A high number of control actions entails frequent use of the communication infrastructure which can highly influence its performance, leading to low and fluctuating bandwidths which in turn increases the time required to transfer data (i.e., latency) [143]. In addition, a high number of control actions can lead to the wear and tear of the corresponding control devices (e.g., tap changer, PV inverter).

Chapter 5

Case Study Part 2: Simulation Analyses for Residential-scale PV systems

5.1 Introduction

The control schemes for residential-scale PV systems, detailed in Chapter 3, are adopted on the real French LV network to assess their performance under different PV penetration levels during summer (i.e., worst case scenario; low demand with high generation). First, a stochastic analysis is performed in section 5.2 to assess the performance of the most common decentralised voltage control approaches (i.e., Volt-Var and Volt-Watt). Thereafter, the performance of the proposed centralised thermal control is investigated in section 5.3. The performance of the proposed combined centralised thermal and decentralised voltage control is presented in section 5.4.

All the minute-by-minute time-series power flow simulations are performed in OpenDSS [144] and driven (using the COM Server) by MATLAB where all the proposed control algorithms are implemented.

5.2 Decentralised Voltage Control

This section investigates the benefits of adopting decentralised voltage control using the Volt-Var and Volt-Watt control functions on the test LV network considering different penetration levels (i.e., 0 to 100%) of residential-scale PV systems for different days in summer (i.e., lowest demand days). The performance of the two control functions (i.e., Volt-Var and Volt-Watt) is investigated for 15 different control set-points (i.e., 15 different Volt-Var and Volt-Watt curves shown in Appendix A and B) adopting the Monte Carlo methodology described in section 4.5.

It is important to highlight that the following analyses assume that all PV inverters in the LV network follow the same curve as the aim is to find a single setting (practical to implement) that brings the most benefits.

5.2.1 Volt-Var Analysis

The 15 investigated Volt-Var curves were defined considering all possible combinations of “deadbands” and “activebands” in steps of 0.02 p.u. To explain the different combinations, *db* can range from 0.00 to 0.08 in steps of 0.02. For each one of these *db* values, the available combinations in *ab* values (also in steps of 0.02 p.u.) are investigated until the point where $V1$ and $V4$ are equal to the French statutory voltage limits. Here, *db* and *ab* are considered in steps of 0.02 in order to reduce the number of investigated scenarios and, therefore, reduce the total computational time of the analyses. $Q1$ and $Q4$ are set to 100% (injecting) and -100% (absorbing), respectively, while $Q2$ and $Q3$ are both set to 0%.

Considering the limited reactive capability of normal residential-scale PV inverters (discussed in section 2.3.1.4), the analysis performed in the following studies investigates both the use of normal and 10% over-rated PV inverters in an effort to understand to which extent the absorption/injection of reactive power can help to keep voltages within the statutory limits without curtailing any PV generation.

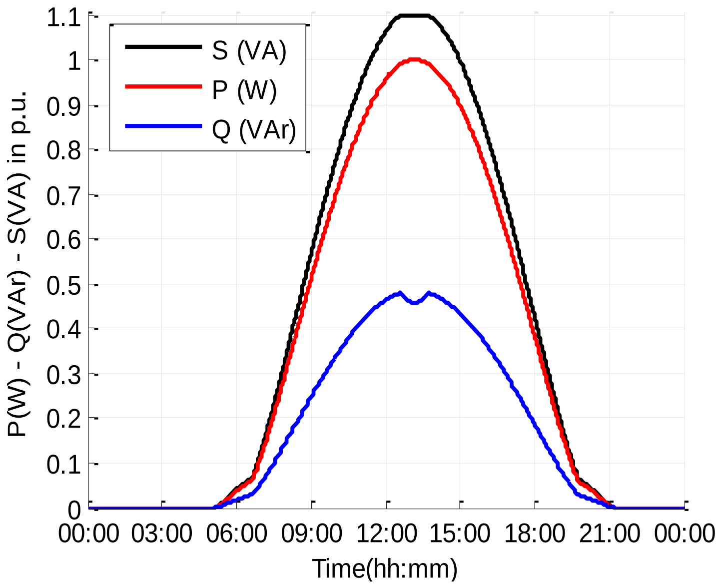


Figure 5-1 Reactive capability of 10% over-rated residential-scale PV inverter

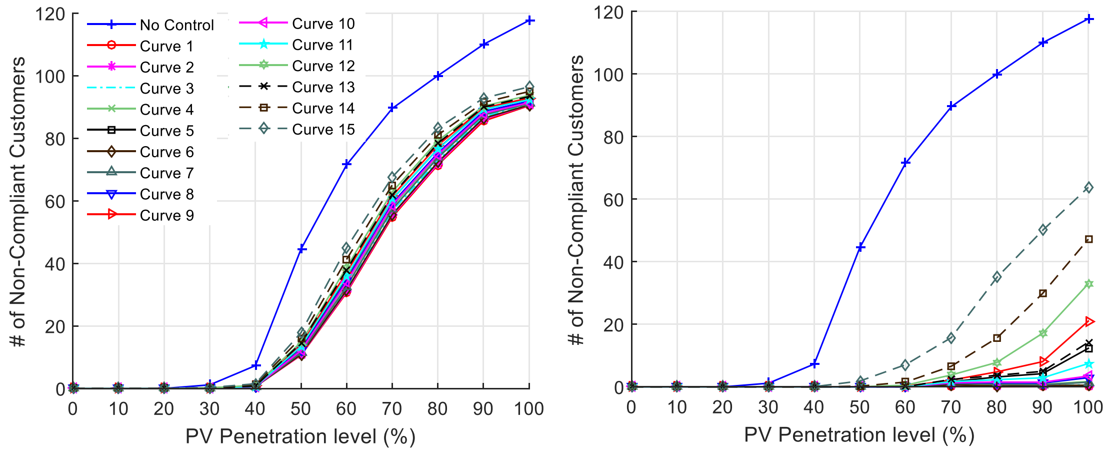
<u>Reactive power capability of over-rated residential-scale PV inverters</u>

To overcome the limitation of normal residential-scale PV inverters, the adoption of over-rated PV inverters can be considered as a potential solution. Adopting a 10% over-rated PV inverter (e.g., S=1.1p.u.) allows to absorb/inject up to 0.46 p.u of reactive power (Var) at peak generation (e.g., $\hat{P}_t = 1\ p.u.$). The reactive capability of a 10% over-rated PV inverter is demonstrated in Figure 5-1 considering 0.9 (leading or lagging) power factor. As the figure shows and compared to the case of a normal inverter (Figure 2-5), during periods of high generation (full irradiance/clear sky) the inverter is still able to absorb or inject reactive power.

5.2.1.1 Voltage Issues

In general, and as expected, without any control, customers experience voltage issues. The majority of voltage issues are caused due to voltage rise as a result of the reverse power flow caused by the PV generation. To demonstrate this and the corresponding performance when adopting a decentralised voltage control, Figure 5-2 shows the average (of 100 Monte Carlo simulations) number of EN 50160 non-compliant customers for each PV penetration level and for each investigated Volt-Var curve. It is demonstrated that without control (blue line with + markers), ~2 customers (in average) might start facing voltage problems at 30% of PV penetration level. As the PV penetration level increases, the number of EN 50160 non-compliant customers is also increasing, reaching the average number of 120 non-compliant customers at 100% of PV penetration.

In general, when the Volt-Var control is adopted, with either normal or 10% over-rated inverters, the number of non-compliant customers decreases for each PV penetration level. Considering the adoption of normal inverters, Figure 5-2 (a), shows that a similar performance is achieved for all the investigated Volt-Var curves where the best performance (compared to the rest) is noticed when using curve 1 (red line with o markers) and 2 (pink line with * markers). This is explained as these curves do not have any ‘‘deadband’’ and they are more sensitive to voltage changes. Hence, all PV systems absorb more reactive power which results in the reduction of voltage level. These results highlight that the adoption of Volt-Var control with normal PV inverters is not very effective in managing voltages as the benefits are minimal due to the limited reactive capability of PV inverters at peak generations periods, where voltages are higher.



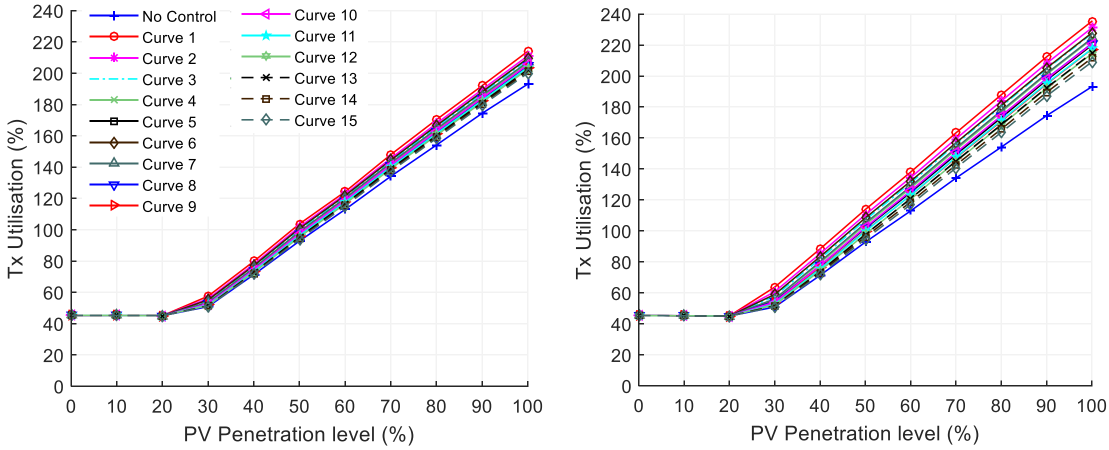
(a) Normal inverters **(b) Over-rated inverters**

Figure 5-2 Voltage issues with Volt-Var control

On the other hand, adopting 10% over-rated PV inverters, a much better performance can be achieved (compared to the case with normal inverters) as the Volt-Var control is able to reduce significantly the number of non-compliant customers. More specific, all results in Figure 5-2 (b) show that the best performance is achieved with the most ‘‘sensitive’’ curves; the shorter the “deadband” and “activeband”, the higher the absorption/injection of reactive power. For example, the application of any curve between 1 and 7 is able to keep all customers compliant with the EN 50160 up to 100% of PV penetration level.

5.2.1.2 Thermal Issues

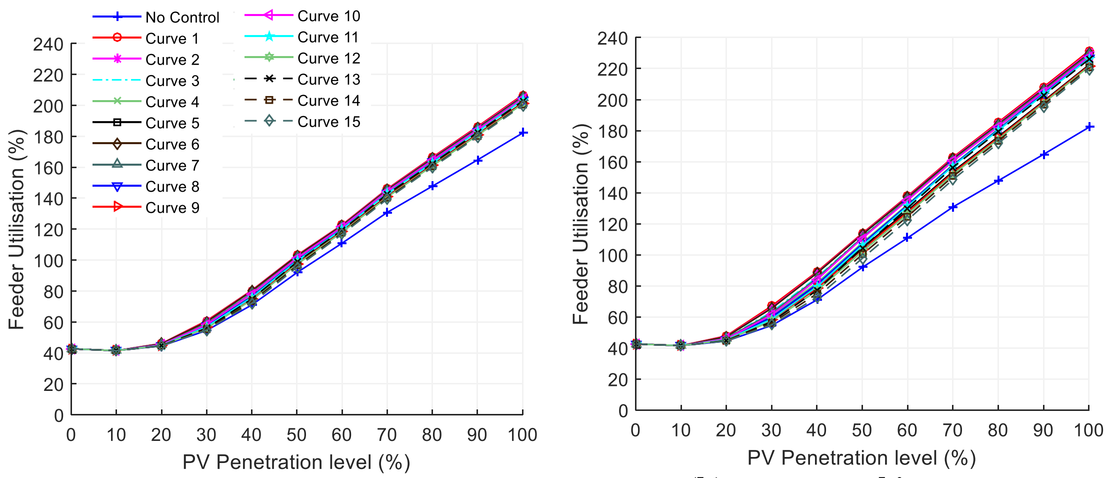
Although the adoption of Volt-Var control allows reducing the number of EN 50160 non-compliant customers, Figure 5-3 and Figure 5-4 show that the utilisation level of the transformer and feeder two (i.e., longest with the highest number of connected customers) increases for all penetration levels above 20% for both normal and over-rated inverters, compared with the case without control. In general, it can be stated that the shorter the *‘‘deadband’’* and *‘‘activeband’’*, the higher the utilisation level of the transformer. This is due to the fact that the transformer has to inject the amount of reactive power that is absorbed by the PV systems which in turn increases the current flowing into the network.



(a) Normal inverters **(b) Over-rated inverters**

Figure 5-3 Transformer utilisation level with Volt-Var control

Considering the adoption of normal inverters and taking the most '*sensitive*' curve (i.e., curve 1) as an example, Figure 5-3 (a) shows that the utilisation level of the transformer increases by ~10 and ~20% (compared to the no control case) at 70 and 100% of penetration levels, respectively. However, adopting 10% over-rated PV inverters, Figure 5-3 (b) shows that the utilisation level of the transformer is increasing by 30 and 40% more (compared to the no control case) at the same penetration levels (i.e., 70 and 100%, respectively). This is due to the fact that the over-rated PV inverters can absorb reactive power (i.e., higher current flowing in the network as the substation has to deliver reactive power) even at high generation periods where the utilisation level is already high.



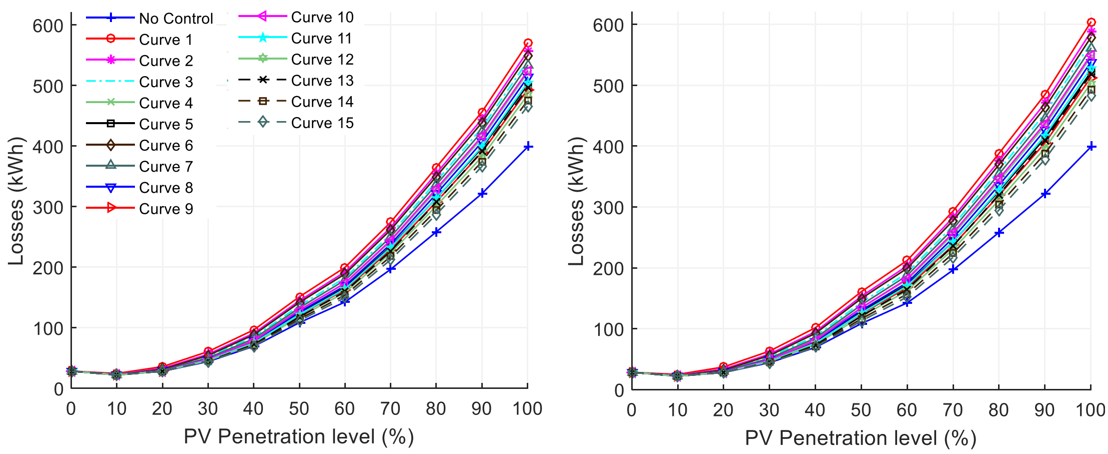
(a) Normal inverters **(b) Over-rated inverters**

Figure 5-4 Feeder utilisation level with Volt-Var control

5.2.1.3 Energy Metrics

Since the adoption of the Volt-Var control does not affect the active power of PV systems (i.e., no active power curtailment is performed), the total energy produced by the PV systems is provided only in the following sections (see Figure 5-8).

However, considering the increased current flow due to the reactive power absorption from the PV systems, the energy losses (in kWh) are expected to increase. Indeed, as Figure 5-5 (a) and (b) show, the energy losses resulting from the adoption of either normal or over-rated inverters increase for all PV penetration levels compared to the case without control. Taking, for example, the case of normal PV inverters with curve 1 (highest losses), losses increase almost by ~30% at each penetration level compared to the case without control. This goes to ~43% when adopting 10% over-rated PV inverters. This is because all PV systems absorb reactive power and, therefore, the transformer has to deliver more reactive power to the LV network. As a result, more current is flowing into the network and the $I^2 \times R$ losses increase. While similar performance is noticed for all the investigated curves, the effect is lower when the ‘‘deadband’’ of the curves increases.



(a) Normal inverters **(b) Over-rated inverters**

Figure 5-5 Total energy losses with Volt-Var control

5.2.1.4 Summary

Normal rated inverters. The analysis demonstrates that the adoption of any of the 15 Volt-Var curves results in a similar, slight reduction of EN50160 non-compliant customers. Overall, voltage rise issues cannot be solved because the ability of the inverters to absorb reactive power is significantly limited during periods of high generation (where voltages are high), i.e., the rated kVA power is almost reached. The utilisation level of the transformer and feeders, however, increases for all penetration levels as this control results in the absorption of reactive power which increases the current flowing in the network. In addition, this control approach results in slightly higher energy losses.

10% over-rated inverters. The analysis demonstrates that, in general, the application of Volt-Var control with over-rated inverters (10% more in this case) can provide a better voltage management (i.e., significant reduction of EN50160 non-compliant customers and, in some cases, shifting PV penetration level) without the need of curtailing any generation. This is due to the fact that an over-rated inverter is able to absorb reactive power even at peak generation periods. The best performance is achieved with the most ‘‘sensitive’’ curves; the shorter the “deadband” and “activeband”, the higher the absorption/injection of reactive power. This control function, however, significantly increases the energy losses and the utilisation level of transformer and feeders.

5.2.2 Volt-Watt Analysis

Similarly to the previous section, the 15 investigated Volt-Watt curves were defined considering all possible combinations of “idlebands” and “activeband” in steps of 0.02 p.u. To explain the different combinations, $V1$ equals to $Vref$ (1.0 p.u.) and ib can range from 0.00 to 0.08 in steps of 0.02. For each one of these ib values, the available combinations in ab values (also in steps of 0.02 p.u.) are investigated until the point where $V3$ is equal to the maximum French statutory voltage limit (1.1p.u.). Similar to the previous section, ib and ab are considered in steps of 0.02 in order to reduce the number of investigated scenarios and, therefore, reduce the total computational time of analyses. $P1$ and $P2$ are set to 100% and $P3$ and $P4$ to 0%.

5.2.2.1 Voltage Issues

Figure 5-6 shows the average (of 100 Monte Carlo simulations) number of EN 50160 non-compliant customers for each PV penetration level based on the applied Volt-Watt curve. The results show that the adoption of the PV inverter Volt-Watt control can eliminate all voltage issues in the LV network with almost any of the investigated Volt-Watt curves. "Curve 15" results in ~5 non-compliant customers at 100% of PV penetration.

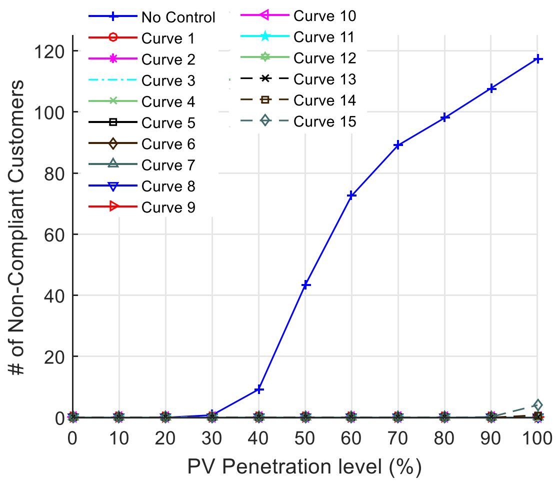


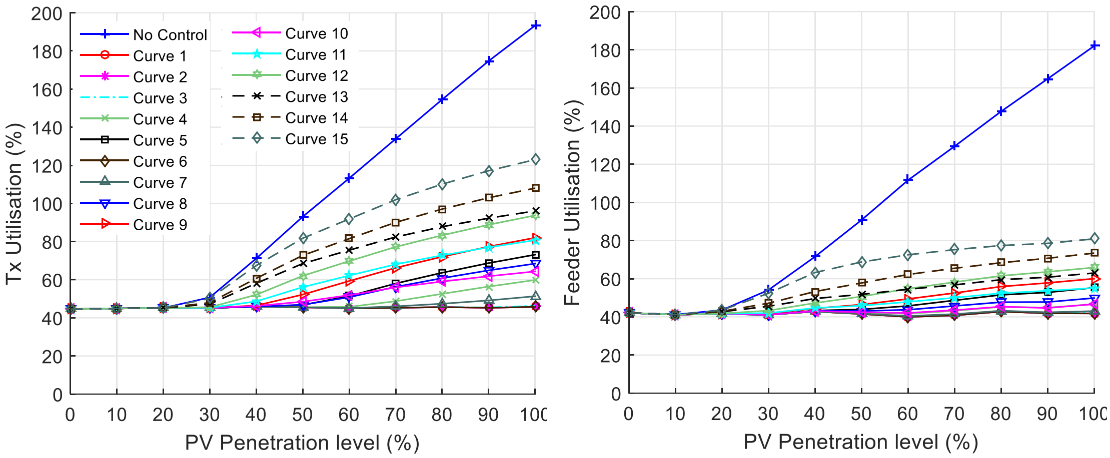
Figure 5-6 Number of EN 50160 non-compliant customers

Therefore, the adoption of the Volt-Watt control can effectively manage voltage issues in PV-rich LV networks. This control, however, comes at the expense of curtailing generation, which is discussed in the following sections.

5.2.2.2 Thermal Issues

As the Volt-Watt control is directly influencing the generation capability (active power – kW) of the PV systems, it is expected that the transformer and feeder utilisation levels will change upon the adoption of Volt-Watt control. Indeed, as Figure 5-7 (a) demonstrates, the transformer's utilisation level significantly reduces with any of the investigated curves. However, although curve 14 (first curve that solves all voltage problems) reduces the transformer's utilisation level below 100% up to 80% of penetration, it is not successful at 90 and 100% of penetration levels. If a curve with shorter ''activeband'' is used, say curve 13, then the transformer's utilisation level is always kept below 100%.

In terms of feeder's utilisation level, Figure 5-7 (b) which demonstrates the utilisation level of Feeder 2 (i.e., the longest with the highest number of connected customers) shows that all curves result in utilisation levels below 100% in comparison with the case where no control is adopted.



(a) Transformer **(b) Feeder**

Figure 5-7 Transformer and feeder utilisation level with Volt-Watt

5.2.2.3 Energy Metrics

Energy Production. Figure 5-8 shows the daily average total energy (kWh) produced by the PV systems for each PV penetration level based on the applied Volt-Watt curves. The case where no control (blue line with + markers) is applied corresponds to the daily average maximum energy that the PV systems can produce at each penetration level. As expected, the higher the penetration, the higher the produced energy.

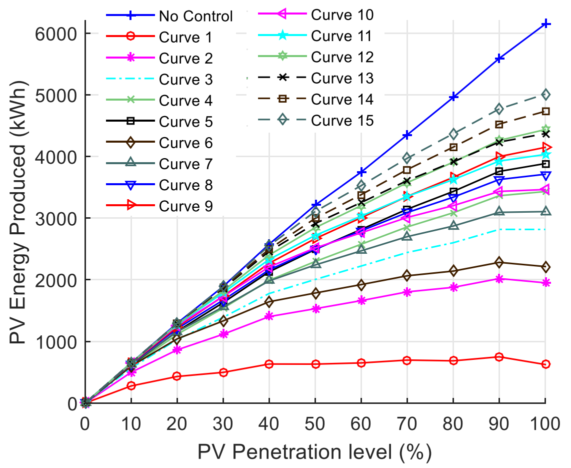


Figure 5-8 Total energy production from PV systems

When the Volt-Watt control is applied (with any of the Volt-Watt curves), generation curtailment occurs. Taking as an example the first curve that solve all voltage issues (curve 14), it can be seen that no energy is curtailed up to 30% of penetration level. However, with a penetration level of 40%, 3% of the energy needs to be curtailed. This increases to 5 and 23% at 50 and 100% of PV penetration levels, respectively. It is important to mention that the shorter the "idleband" and "activeband", the higher the curtailment. This can be noticed with the adoption of curve 1 as most of the energy is curtailed due to the high voltage sensitivity of the controller.

Energy Losses (kWh). As the generation is curtailed due to the Volt-Watt control, losses are expected to be lower since less current is flowing in the network. Indeed, Figure 5-9 proves this concept showing that the energy losses are reduced significantly depending on the applied Volt-Watt curve. Of course, the higher the curtailment, the lower the losses, as shown in the results using curve 1. Considering the curve that solves all voltage problems, curve 14, the losses start reducing by 14% at 40% of penetration level. This figure goes up to 23 and 56% at 50 and 100% of penetration levels, respectively.

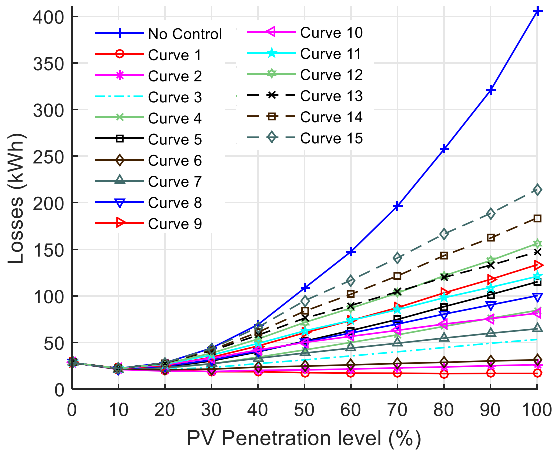


Figure 5-9 Total energy losses

5.2.2.4 Summary

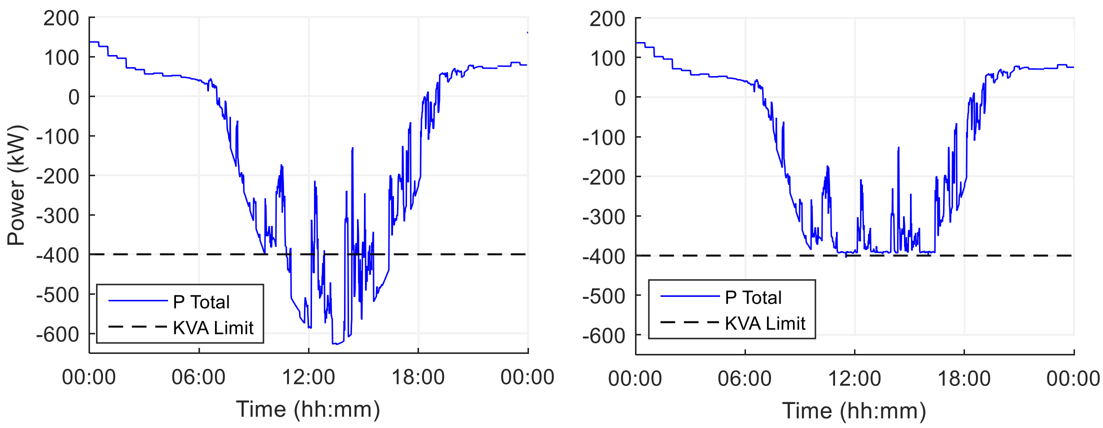
The analysis demonstrates that this approach is more effective in managing voltages. Indeed, most of the curves show that the penetration level of PV systems can be potentially shifted to 100% without facing any voltage problems. The analysis also shows that a single Volt-Watt curve (i.e., curve 15) can be found that provides the best trade-off between voltage issues and the required volume of curtailment. In terms of the transformer and feeder utilisation levels, the analysis shows that the utilisation levels are always kept below 100%, except for two curves (i.e., 14 and 15) where assets are still overloaded at high penetration levels.

5.3 Centralised Thermal Control (CTC)

This section investigates the benefits of adopting the proposed centralised thermal control to manage thermal issues in PV-rich LV networks by limiting the generation capability of PV systems. First the time-series performance of the proposed method on the test LV network is presented. Its performance is then stochastically investigated considering different penetration levels of residential-scale PV systems for different days in summer (i.e., lowest demand days).

5.3.1 Time-Series Performance

In order to describe the time-series performance of the proposed centralised thermal control, a deterministic single case scenario is illustrated in this section adopting 1-min control cycles. The performance is compared with the case where no control is applied. The test LV network considers 70% of PV penetration (i.e., 777kWp PV capacity) and the load profiles for each customer are randomly selected and allocated based on the procedure described in section 4.3.2 for the day 15 June 2014 (considered to have the lowest demand during summer). The PV systems are randomly allocated in the network based on the selected penetration level and assumed to be either 3kWp or 6kWp systems, sharing the same generation profile in June (summer).



(a) No control **(b) CTC, 1-min**

Figure 5-10 Monitored power at transformer

Figure 5-10 (a) shows the daily 1 minute active power monitored at the transformer for the case without control. As it can be seen, the transformer is overloaded during 10am and 4pm. This is because the sun irradiance during this period is high and PV systems are generating at maximum. The same behaviour can be noticed at the head of each feeder, as shown in Figure 5-11 (active power monitored per phase at the head of each feeder). More specifically, Feeder 2, which has the highest number of PV systems installed, faces thermal issues as the reverse power flow is higher than the capacity of the cable. It is also important to mention that the total produced energy from PV systems was 5.31MWh.

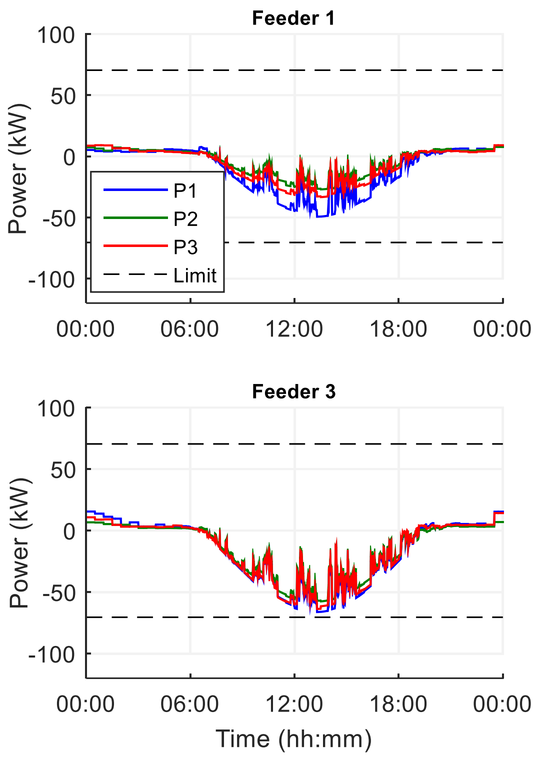
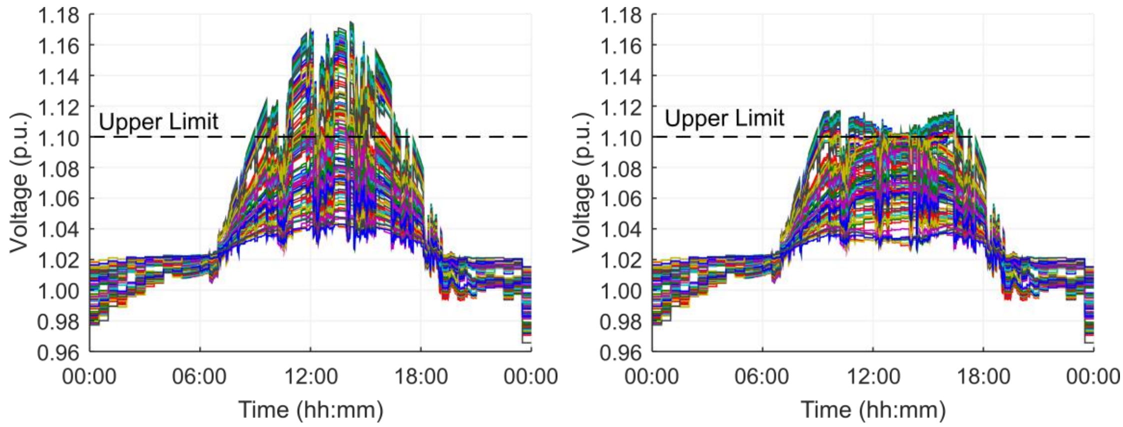


Figure 5-11 Monitored 3-phase power at the head of feeders – No control

In terms of voltage issues, the number of EN 50160 non-compliant customers is 112 and the 1-minute daily voltage profiles of all 162 customers in the network is shown in Figure 5-12 (a). Voltage rise issues can clearly be seen during the peak generation hours.

However, when the centralised thermal control is adopted, thermal issues are eliminated (see power monitored at the transformer and feeders in Figure 5-10 (b) and Figure 5-13, respectively); both transformer and feeders are always below their thermal limits. This is the result of using an active power limit that ensures the maximum possible PV generation without violating the thermal limits. The active power limit $pctP_{F_n}^{s.p.}$ for PV systems in Feeder 2, presented in Figure 5-14, shows that the generation limit is reduced to keep the transformer and feeder utilisation limits within the limits as opposed to the case without control.

Moreover, considering that the reduction of generation affects the voltage, it is also important to highlight that the number of EN 50160 non-compliant customers is reduced to 64. The 1-minute daily voltage profiles of all customers are shown in Figure 5-12 (b). As expected, the voltage level is reduced significantly for each customer.



(a) No control **(b) CTC, 1-min**

Figure 5-12 Daily 1-minute voltage profiles of every customer

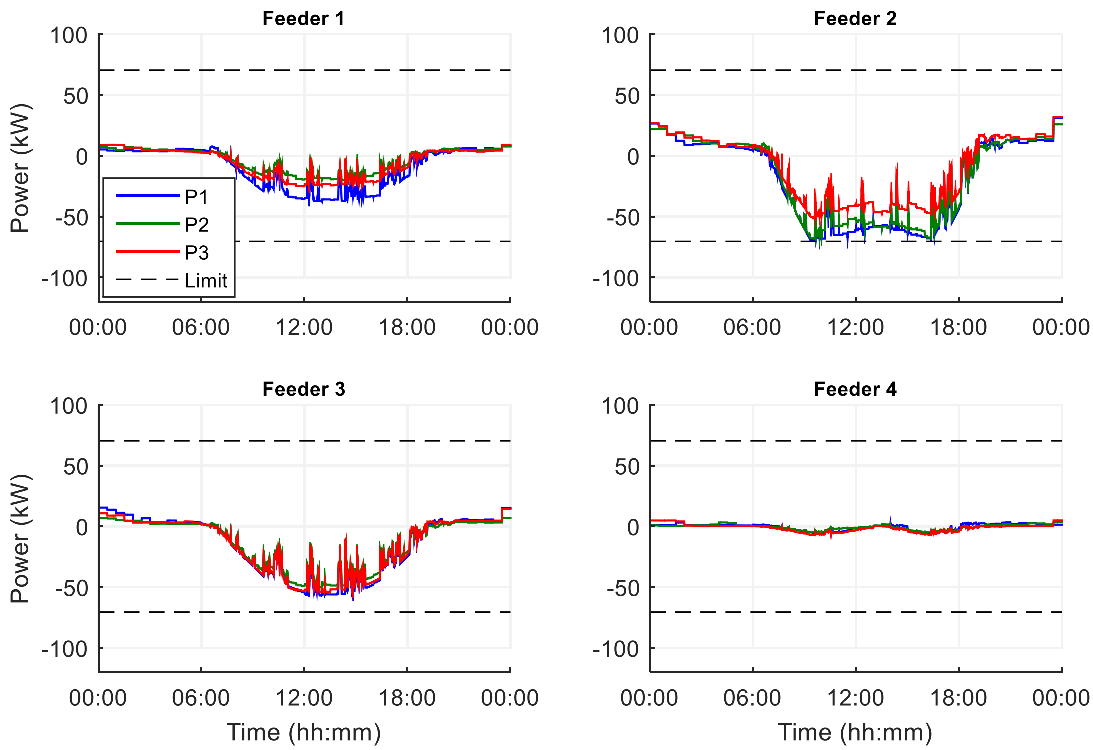


Figure 5-13 Monitored 3-phase power at the head of feeders – CTC, 1-min

In terms of energy produced in this specific case (one single day), the proposed solution resulted in the production of 4.54MWh of generation where the case without control resulted in 5.31MWh. Thus, the adoption of the proposed centralised thermal control was able to solve all thermal issues with the expense of curtailing 14.5% of the total generation. Although curtailment of generation might be considered as reduced profit to the PV system owner, it is important as it allows accommodating even more LCTs in LV networks without the need of costly network reinforcements, thus accelerating the transition towards an eco-friendly low carbon environment.

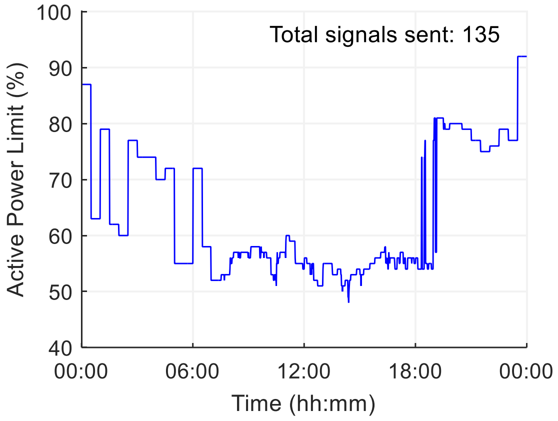


Figure 5-14 Active power limits for PV systems – CTC, 1-min

5.3.2 Stochastic Analysis

In this section the proposed centralised thermal control is applied on the real French LV network considering different penetration levels of PV systems during summer (i.e., lowest demand days, highest generation). The performance of the proposed control logic is investigated by applying the Monte Carlo methodology as described in section 4.5 and adopting four different control cycles (i.e., 1, 10, 20 and 30-min). The simulation results shown in this section present and assess the benefits and disadvantages of adopting the proposed control method.

5.3.2.1 Voltage Issues

Figure 5-15 shows the performance of the proposed centralised thermal control in terms of the average number of customers (considering all Monte Carlo simulations) which are not compliant with the EN 50160 standard. The influence of different control cycles (i.e., 1, 10, 20 and 30-min) and the average standard deviation for each penetration level is presented with a different line colour.

Although the primary goal of the proposed control approach is to manage thermal issues, results show that, overall and considering all control cycles, the number of non-compliant customers reduces significantly from 50% of penetration level and onwards. This outcome occurs as a natural effect of the proposed control approach which instructs the PV systems to reduce their maximum generation point (i.e., curtailment) in order to manage thermal issues; thus, the customer's voltage level is reduced with the reduction of active power.

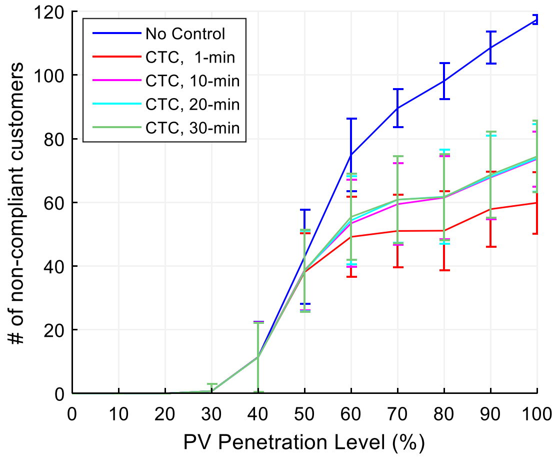


Figure 5-15 CTC - voltage issues

The best performance is achieved when adopting 1-min control cycles (red line) as the active power limit for the PV systems is calculated more frequently using the monitoring data of the last minute (higher accuracy). For example, taking into account all penetration levels above 60%, the number of customers facing voltage issues is on average 10 less than the number when adopting 10, 20 and 30-min control cycles. To provide more details, adopting 1-min control cycles and considering 70 and 100% of penetration levels, the number of customers facing voltage issues reduces from 90 and 120 (without control) to 50 and 60, respectively.

In general, it is highlighted that although the proposed centralised thermal control cannot shift the occurrence of voltage issues to a higher penetration level, it reduces the magnitude of voltage issues across all penetration levels above 50%.

5.3.2.2 Thermal Issues

In terms of thermal issues, Figure 5-16 (a) shows the transformer's average maximum utilisation level for the cases without (blue line) and with control (centralised thermal control) adopting four control cycles (i.e., 1, 10, 20 and 30-min).

Without control the transformer's maximum utilisation remains stable around 45% until 20% of PV penetration level and increases thereafter. The aforementioned behaviour is noticed when the local production is higher than the local consumption and the MV/LV transformer starts to export energy to the MV network. Thus, higher penetration levels produce more power to be exported and, therefore, result in a higher utilisation of the electric infrastructure. The maximum utilisation level (100%) is reached in average after 50% of PV penetration, where the transformer is significantly overloaded.

To add more value to these results, Figure 5-16 (b) presents the percentage of time during a day that the transformer's utilisation level is above its kVA limit. For example, considering the case without control (blue bars), the transformer is overloaded for 6, 17 and 24% of the day at 60, 80 and 100% of PV penetration, respectively.

The feeders' utilisation presents a similar behaviour to that of the transformer without control. This is noticable in Figure 5-17 (especially for Feeders 2 and 3), which presents the average maximum utilisation level of the first segment of each feeder. The utilisation level of all feeders, except Feeders 2 and 3, remains below 100% for all penetration levels. For example, the utilisation level of Feeder 2 remains stable until 20% of PV penetration and increases rapidly from 30% onwards. The maximum utilisation level (100%) of Feeder 2 is reached in average after 40% of PV penetration. This shows that this Feeder will be overloaded earlier than the transformer (which might occur after 50% of PV penetration). The maximum utilisation level for Feeder 3 is reached in average after 90% of PV penetration.

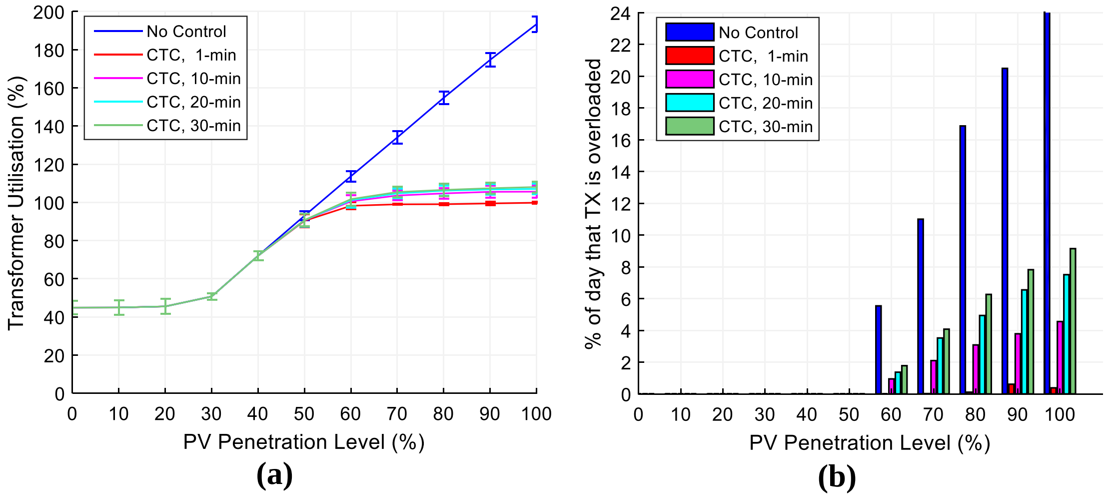


Figure 5-16 CTC - (a) transformer utilisation and (b) % of day overloading

However, the adoption of the proposed centralised thermal control shows that with either control cycle is possible to significantly reduce the transformer's and feeders' maximum utilisation levels as illustrated in Figure 5-16 (a) and Figure 5-17, respectively. Considering the transformer and the penetration levels where the transformer is overloaded without control (i.e., above 50%), the average maximum utilisation level (considering all Monte Carlo simulations) is always below 100% when adopting 1-min control cycles and below 108% for the other control cycles (i.e., 10, 20 and 30-min). The same effect is also noticed considering feeder utilisation levels and, particularly, in Feeder 2 which is the most loaded. It is important to mention that these figures represent the average maximum utilisation level recorded throughout the day and it does not mean that the assets are always operating at these levels.

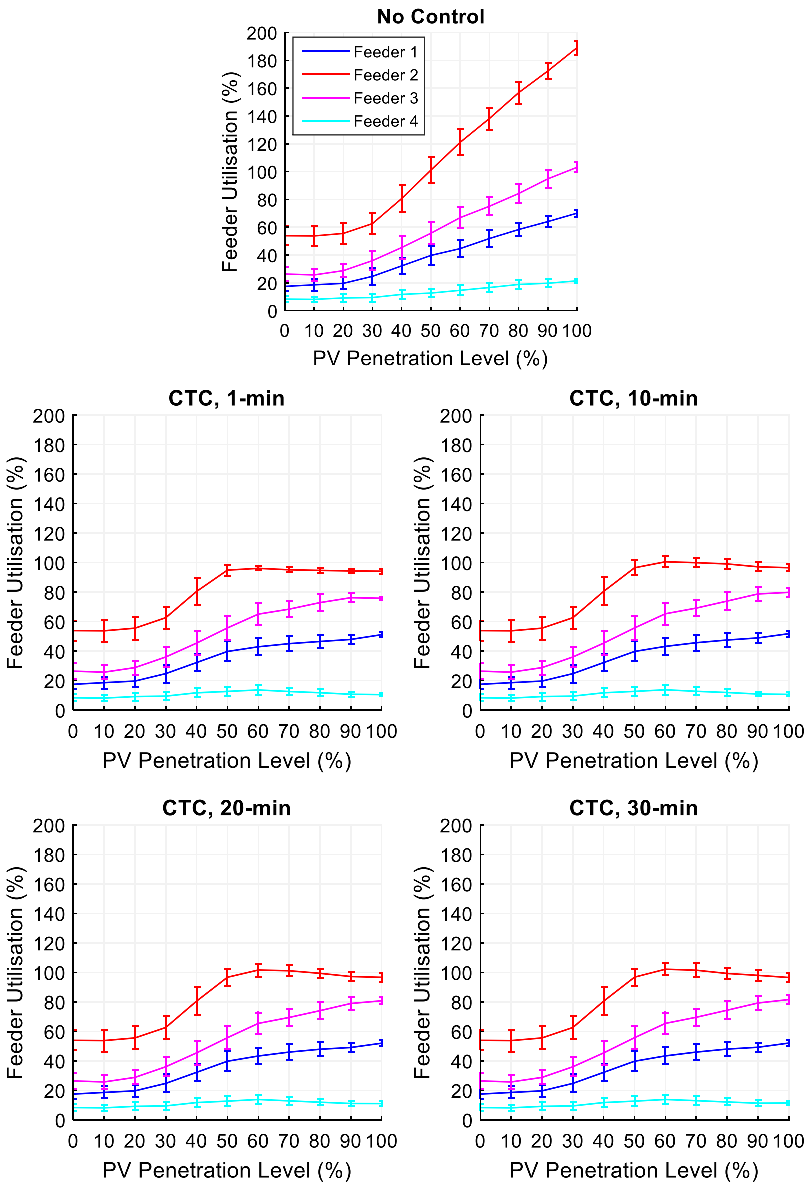


Figure 5-17 CTC - Feeders' utilisation levels

The percentage of the time during the day that the transformer is overloaded (i.e., utilisation level above the kVA limit) is significantly decreased when adopting the centralised thermal control. For example, as observed in Figure 5-16 (b) and considering 100% of PV penetration, the period within the day where the transformer is above its kVA limit decreased by almost 24, 20, 17 and 15% for the 1, 10, 20 and 30-min control cycles, respectively. Results also show that the longer is the control cycle, the more will be the period (within a day) where the utilisation of the assets might be above their kVA limit. This can be explained as specific active power limit set-points ($pctP_{F_{n_i}}^{s.p.}$), provided at the beginning of a control cycle, might not cater for sudden irradiance and demand changes until the next control cycle.

A possible solution to cater for this issue is to use a more conservative (lower) thermal threshold (i.e., a) for the centralised thermal controller, so as to curtail generation at lower utilisation levels. Similarly, another solution can be considered to reduce the duration of the control cycle when asset utilisation exceeds a second (higher) threshold.

In general, considering these results (i.e., maximum utilisation level of transformer and feeders) the proposed centralised thermal control proves to be effective in managing thermal issues in LV networks.

5.3.2.3 Energy Metrics

Figure 5-18 (a) shows the daily average total energy (kWh) produced by the all PV systems for each penetration level with and without the centralised thermal control. The case without control (blue line) shows that the higher the penetration, the higher the produced energy. A total of 3.8, 4.9 and 6.1 MWh of energy is produced at 60, 80 and 100% of PV penetration levels, respectively.

On the other hand, the adoption of the centralised thermal control, as expected, leads to the curtailment of energy generated from the PV systems and the same performance is achieved with any of the investigated control cycles. Considering the results, no energy is curtailed up to 50% of penetration level where at 60% of PV penetration, 2% of the energy is curtailed. This increases to 12 and 22% at 80 and 100% of PV penetration level, respectively.

In addition to the aforementioned, when adopting the centralised thermal control, energy losses are expected to reduce as less current is flowing in the network (due to generation curtailment). Indeed, this can be seen in Figure 5-18 (b) where energy

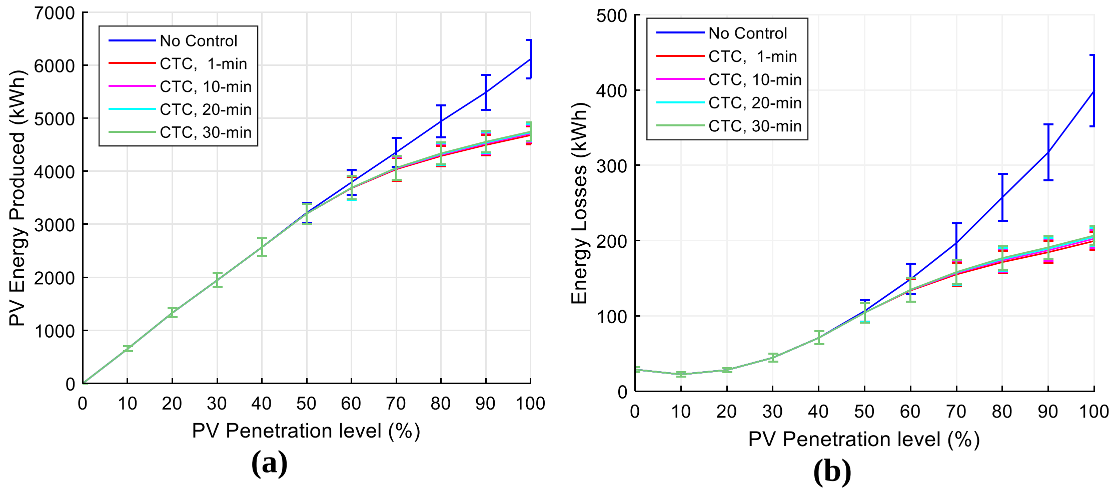


Figure 5-18 CTC - (a) energy produced and (b) network energy losses

losses are reduced significantly when energy (same performance in all investigated control cycles). To give an example, losses start reducing by 9.5% at 60% of penetration level. This figure goes up to 31.5 and 48.2% at 80 and 100% of penetration levels, respectively. However, it is important to highlight that the losses presented here correspond to the theoretical losses (e.g., assuming no network reinforcement, no limitation of PV system installations) where the power flow can be higher than the rated power of the feeder.

5.3.2.4 Control Actions

Figure 5-19 shows the average and standard deviation of the number of signals sent to PV systems within the day for each penetration level and control cycle, respectively.

As expected, results demonstrate that the length of control cycles is directly influencing the number of signals sent to the PV systems throughout the day. In general, the higher the penetration, the more the number of PV signals. Conversely, the longer the control cycle, the fewer the number of signals.

Considering the number of PV signals, the best performance is achieved with 30-min control cycles where the maximum number of PV signals sent throughout the day is around 40 (average) and significantly lower than the other control cycles (i.e., 160, 78 and 60 for 1, 10 and 20-min control cycles).

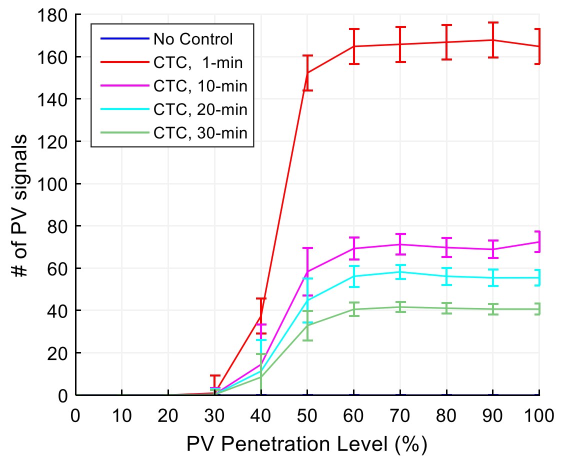


Figure 5-19 CTC - number of PV signals sent

5.3.3 Summary

The analysis demonstrates that the proposed centralised thermal controller is an effective solution to manage and solve thermal issues and slightly improve, indirectly, customer voltages. The maximum utilisation level of both transformer and feeders is significantly reduced to values close to the capacity limits; asset utilisation is always below 108% for all control cycles except 1-min where the utilisation never goes above 100%. The number of customers which experience voltage issues is significantly reduced as a natural result of reducing the maximum active power limit of PV systems. Although the adopted (and investigated) control cycles (i.e., 1, 10, 20 and 30-min) do not significantly influence the performance in terms of thermal and voltage issues, it is highlighted that the shorter the control cycle, the better the performance. On the contrary, shorter control cycles lead to higher number of control actions (i.e., PV signals in this case) which might cause operational challenges (i.e., communication). Hence, for this case study, the 30-min control cycle can be considered as a trade-off control setting between the number of control actions and operation performance (in terms of thermal and voltage issues).

5.4 Combined Centralised Thermal and Decentralised Voltage Control

As the last two sections (i.e., 5.2, 5.3) demonstrate, the adoption of the corresponding proposed control schemes, although being effective, they primarily address only one technical issue: either voltage or thermal. Here, the performance of the proposed combined centralised thermal and decentralised voltage control is assessed on the real French LV network to provide a more complete active network management solution (i.e., management of both thermal and voltage issues).

The analysis is performed adopting the most adequate operational settings (i.e., Volt-Watt curve, control cycle) found in the previous analyses. Therefore, 30-min control cycles are adopted for the centralised thermal control and for the decentralised voltage control all PV inverters adopt the Volt-Watt curve 15 (Figure 5-20), which is identified as the most suitable to manage voltage issues while requiring the least generation curtailment (takes action only if the voltage, at the connection point, is higher than 1.08 p.u.).

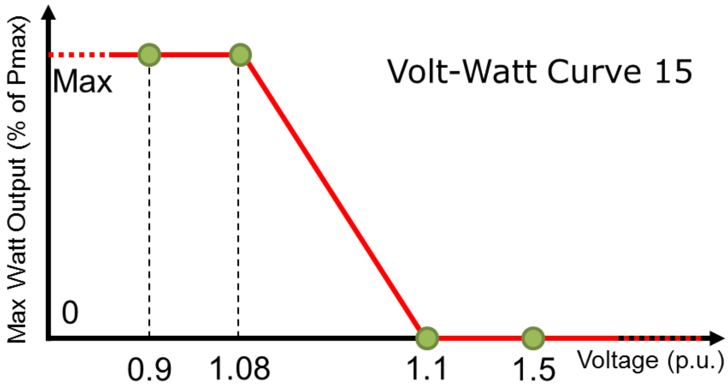


Figure 5-20 Volt-Watt curve 15

The coordination between the centralised and decentralised controllers will naturally be achieved with the adopted control cycle (i.e., 30-min) where the decentralised voltage controller will have priority (i.e., acting first). More specifically, as voltage issues in PV-rich LV networks are usually occurring at an earlier penetration than thermal issues, the decentralised voltage controller which works in real time (e.g., fraction of a second) will be acting first while the centralised thermal controller will be acting (if needed) every 30 minutes. This provides coordination between the two controllers while giving priority to the decentralised one.

5.4.1 Time-Series Performance

In this section, the time-series performance of the proposed combined centralised thermal and decentralised voltage control is illustrated considering the same deterministic single case scenario used in section 5.3.1.

In general the time-series performance highlights that the proposed combined control approach is effectively managing both thermal and voltage issues. The power monitored at the transformer (Figure 5-21) and feeders (Figure 5-22) is always kept below the corresponding capacity limits of the assets. In addition, it can be observed that the monitored power is slightly lower at peak generation periods compared to the case where only the centralised thermal control is applied (see Figure 5-10 (b) and Figure 5-13 in section 5.3.1). This is, in fact, an effect of the decentralised voltage control (i.e., Volt-Watt) which forces an additional reduction of the PV generation in order to keep voltages within the statutory limits.

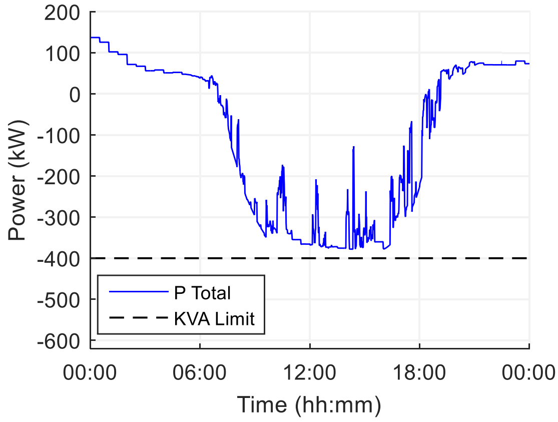


Figure 5-21 Monitored power at transformer, CTC + Volt-Watt

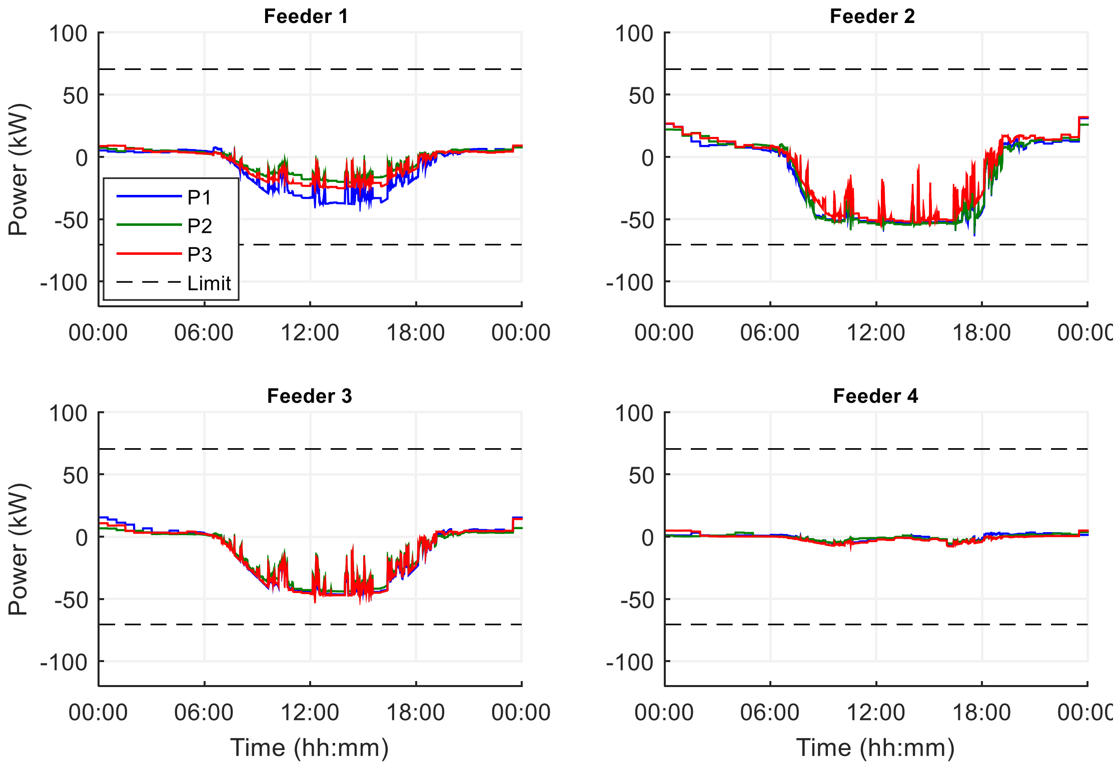


Figure 5-22 Monitored 3-phase power at the head feeders – CTC + Volt-Watt

Indeed as Figure 5-23 illustrates, the voltage profiles of all customers in the test LV network, compared to the one where only the centralised thermal controller is applied (see Figure 5-12, section5.3.1), are always below the statutory voltage limits and, hence, all customers are compliant with the standard EN 50160.

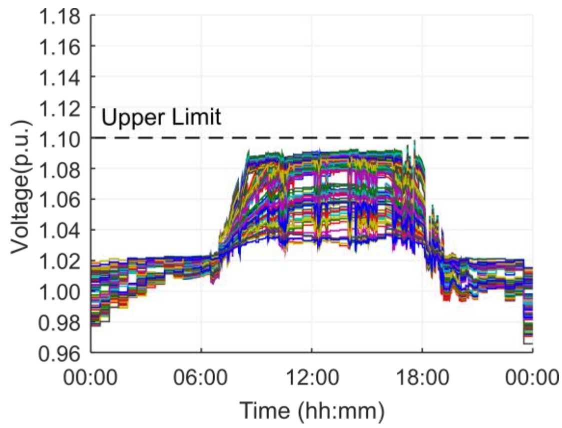


Figure 5-23 Daily 1-minute voltage profiles of every customer, CTC + Volt-Watt

However, and as expected, to achieve this performance, an additional 4% of the total energy produced by the PV systems when the centralised thermal control is applied alone had to be curtailed. In total, considering the case without control, the proposed combined control method is able to solve all voltage and thermal issues by curtailing 17.87% of the total potential PV generation. As previously mentioned, although curtailment of generation might be considered as reduced profit to the PV system owner, it is important to highlight that it allows accommodating higher number of LCTs in LV networks without the need of costly network reinforcements, thus accelerating the transition towards an eco-friendly low carbon environment. As an alternative to this and considering the adoption of residential-scale BES systems, this amount of energy, otherwise curtailed, could be stored and used by the customer to support household demand when needed (more details in the following sections).

5.4.2 Stochastic Analysis

Same as in section 5.3.2, the performance of the proposed combined centralised thermal and decentralised voltage control is stochastically assessed (i.e., Monte Carlo methodology) on the test LV network considering different penetration levels of PV systems during summer (i.e., lowest demand days, highest generation).

5.4.2.1 Voltage Issues

As demonstrated in Figure 5-24, the proposed combined method found to be effective in eliminating all voltage issues, regardless the penetration level of PV systems. In contrast to the case where only the centralised thermal control is applied, the decentralised voltage control, as expected, provides additional flexibility in terms of voltage management. Overall, the network's hosting capacity (in terms of voltage issues) is shifted to 100% without facing any voltage issues when the combined centralised and decentralised control is adopted.

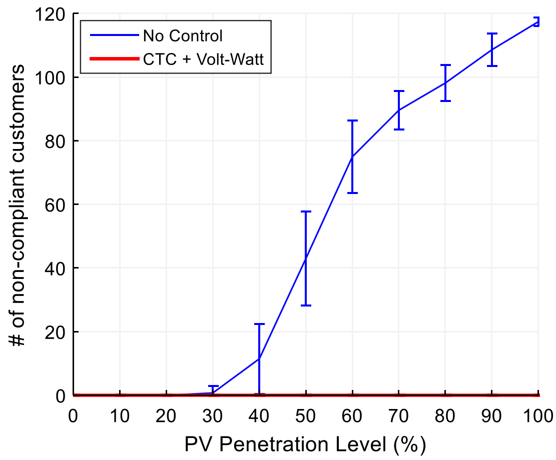


Figure 5-24 CTC + Volt-Watt - voltage issues

5.4.2.2 Thermal Issues

Furthermore, as demonstrated in Figure 5-25 (red line) and Figure 5-26 (right), the adoption of the combined centralised thermal and decentralised voltage control is also able to keep the utilisation level of both transformer and feeders below 100% for all penetration levels.

Nonetheless, it is important to highlight that with this approach, the utilisation levels of the assets are slightly lower compared to the centralised thermal control (see Figure 5-16). As previously discussed, this is due to the fact that the decentralised voltage control (i.e., Volt-Watt) results in additional PV generation reduction to bring voltages within the statutory limits. This effect can be noticed at lower penetrations (i.e., 40 and 50%) where the transformer's utilisation level, adopting the combined control method, is slightly lower than the one resulting from the case where only the centralised method is considered. Despite the fact that no asset is facing thermal issues at these penetration levels (i.e., 40 and 50%), customers are experiencing voltage issues. Hence, the decentralised voltage control reduces the PV generation to manage voltages.

In general, these results (i.e., utilisation level of transformer and feeder) show that the combined centralised thermal and decentralised voltage control is able to provide an efficient thermal management in PV-rich LV networks.

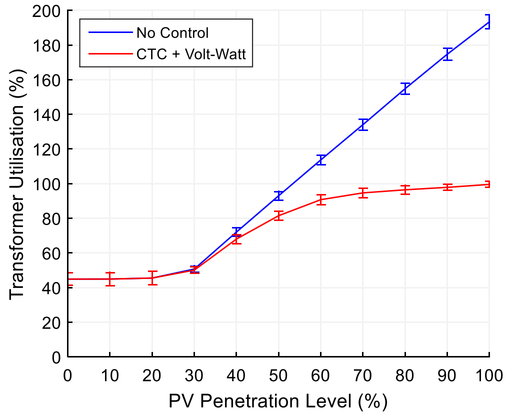


Figure 5-25 CTC + Volt-Watt - transformer utilisation level

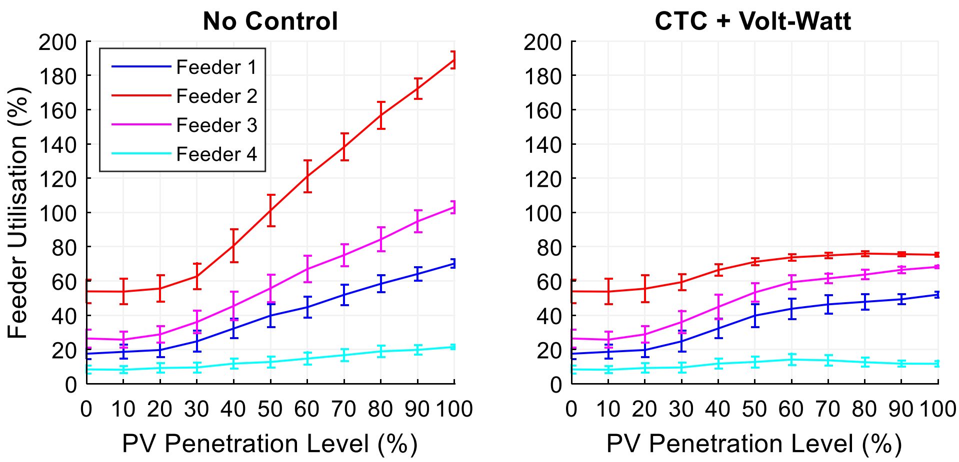


Figure 5-26 CTC + Volt-Watt - Feeders' utilisation levels

5.4.2.3 Energy Metrics

Aligned with the previously discussed results, Figure 5-27 (a), which presents the total energy produced from PV systems, shows, as expected, that the combined control method results in slightly more energy curtailment in order to manage both voltage and thermal issues. It is important to mention that the additional energy curtailment is happening at the penetration levels where the centralised thermal controller is not acting or its actions are not enough to solve those issues (i.e., penetrations levels between 40-80%, see Figure 5-18). To be more specific, energy is not curtailed for up to 40% of penetration level where at 50%, 3.27% of the total energy is curtailed. This figure increases to 16.32 and 25.47% at 80 and 100% of PV penetration level, respectively. Overall, the combined control method, compared to the case where only the centralised thermal control is adopted, results in an average of 3% more curtailed energy for each penetration level (above 40%).

The same performance is also observed considering the energy losses. As shown in Figure 5-27 (b), losses start reducing by 12.85% at 50% of penetration level. This goes up to 41.48 and 54.5% at 80 and 100% of penetration levels, respectively. Yet again, it is important to highlight that the losses presented here correspond to the theoretical ones (e.g., assuming no network reinforcement, no limitation of PV system installations) where the power flow is allowed to be higher than the rated power of the feeder.

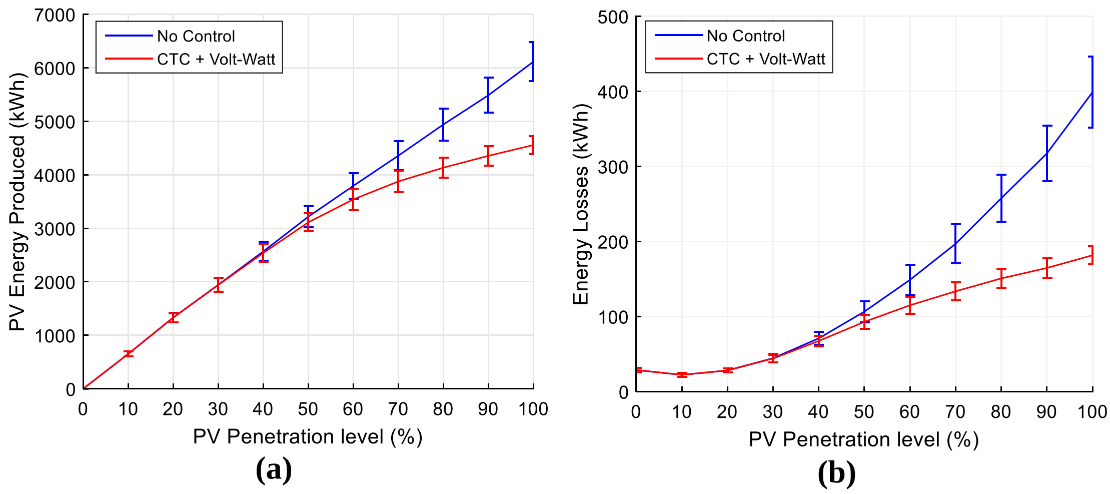


Figure 5-27 CTC+Volt-Watt-(a) energy produced and (b) network energy losses

5.4.2.4 Control Actions

Finally, in terms of control actions per day, Figure 5-28 shows that the proposed combined control method achieves the same performance as the one when the centralised thermal control is applied alone (see Figure 5-19, CTC, 30-min). In general, no PV signals are sent up to 30% of penetration due to the fact that the utilisation of the assets (i.e., transformer and feeders) is always below their capacity limits. Thereafter, the number of signals increases with penetration; reaching the maximum of 40 (average) per day.

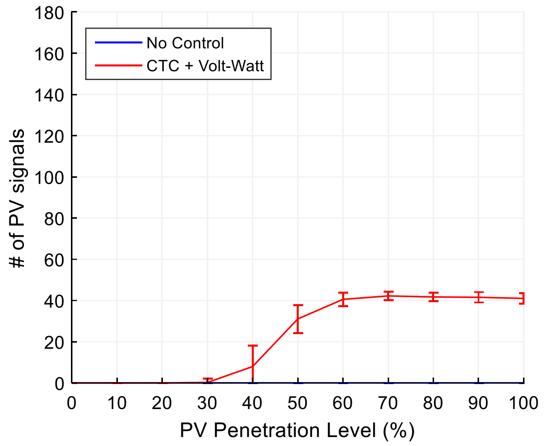


Figure 5-28 CTC+Volt-Watt – Number of PV signals

5.4.3 Summary

Compared to the control schemes investigated in sections 5.2 and 5.3, the adoption of the proposed combined thermal and decentralised voltage control provides a more robust active network management in PV-rich LV networks, as it effectively eliminates both voltage and thermal issues. However, to achieve this excellent performance, which allows shifting the network's hosting capacity to 100%, the analysis demonstrates that slightly more energy needs to be curtailed compared to the previously investigated control methods (i.e., average 3% more at each penetration level compared to the centralised thermal control alone).

These findings clearly indicate that the proposed combined centralised thermal and decentralised voltage control can be a potential solution to efficiently manage both thermal and voltage issues.

Chapter 6

Case Study Part 3: Simulation Analyses for Residential-scale BES Systems

6.1 Introduction

The proposed "advanced operation" mode for residential-scale BES systems, detailed in Chapter 3, is adopted here on the real French LV network to assess its performance under different PV penetration levels during summer (i.e., worst case scenario; low demand, high generation). For demonstration purposes its performance is compared against the "normal operation" mode adopted based on available specifications from BES system manufacturer (as detailed in section 3.3.1). A time-series analysis is first performed on the two BES operation modes. Then, their performances are assessed adopting a stochastic analysis considering different PV penetration levels. This quantitative assessment allows understanding the benefits of adopting residential-scale BES systems in combination with PV systems in order to maximise the storage utilisation while managing voltage and thermal issues.

All the minute-by-minute time-series power flow simulations are performed in OpenDSS [144] and driven (using the COM Server) by MATLAB where all the proposed control algorithms are implemented.

6.2 Technical Specifications

The studies performed here consider the installation of a widely popular residential-scale BES system, currently available in the market. While there is a wide selection of lithium-ion batteries that could have been selected, the Tesla Powerwall [92] is becoming immensely popular, and paired with its low price (per kWh), it was considered as the most appropriate one to be modelled.

The basic technical specifications of the modelled BES provided by Tesla Motors are given in Table 6-1.

Table 6-1 Modelled BES System - Basic Specifications [92]

Product Name	*Tesla Powerwall*
Technology	*Rechargeable lithium-ion battery*
Capacity	*10kWh*
Power	*3.3kW*
Efficiency	*92.5% DC round-trip efficiency (includes the inverter)*
Depth of discharge	*100%*
Compatibility	*Single-phase and three-phase*

It is important to highlight that although Tesla Powerwall allows a full range of discharge depth (i.e., 100%) the studies in this Thesis adopt a 10% upper and lower battery reserve. These limits, as shown in Figure 6-1, mean that the BES system is able to charge up to 90% and discharge down to 10% of the available capacity. Adopting such limits helps maintaining the lifespan of the battery [136].

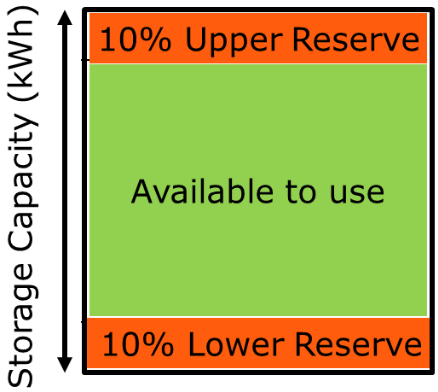


Figure 6-1 Modelled Charging and Discharging Depth

6.2.1 BES Sizing

After several discussions with the industrial partner, EDF R&D, the following approach to size BES systems was agreed as it creates realistic and challenging scenarios (important to assess the extent to which the proposed method is able to provide benefits). It is assumed that every household with a PV system installation is equipped with a BES system. The size of the BES systems allocated to a specific household is defined by the PV system's installed capacity. This is described below:

A basic[3] PV system installation gets a basic BES system which is considered to have a 10kWh storage capacity with 3.3kWp power. For instance:

- For a household with one basic PV system (i.e., 1×3kWp capacity), one basic BES system (i.e., 1×10kWh with 1×3.3kWp) is allocated.

- For a household with two basic PV systems (i.e., 2×3kWp capacity), two basic BES systems (i.e., 2×10kWh with 2×3.3kWp) are allocated.

6.3 Additional Performance Metrics

This section contains the definition of additional metices that help assessing the performance of residential-scale BES systems from the perspective of both the grid and the customers. All metrices are assessed independently for each customer, i.e., the interactions between customers do not matter. For example, if "Customer A" exports energy into the LV network which is then used by "Customer B", the corresponding interaction is not quantified.

6.3.1 Grid Dependency Index (GDI)

The GDI quantifies how much of the total customer's energy consumption is provided by the LV network. As shown in (6.1), the GDI is defined as the ratio of daily energy imported (E_{import}^{house}) from the grid to the house over the daily household energy consumption ($E_{consumption}^{house}$). A value of 100% indicates that all the energy consumed by the house is provided by the grid, while a value of 0% indicates that all the energy consumed is self-supplied (excess PV generation stored by the BES system). This index helps understanding the impact on the electricity bill of a household. The lower the GDI, the less dependent is the household from the grid, thus resulting in lower bills.

$$GDI = \frac{E_{import}^{house}}{E_{consumption}^{house}} \tag{6.1}$$

[3] As defined in section 4.4.2, a basic PV system is considered to have an installed capacity of 3kWp

6.3.2 LV Network Energy Imports

This metric quantifies the total daily energy imported from grid at the busbar of the secondary substation. This allows understanding how BES systems reduce the grid dependency of the network.

6.3.3 State of Charge (SOC)

The daily SOC profile is used as a metric to understand how the BES system is using its storage capacity throughout the day.

6.3.4 Adopted Advanced Operation Mode Settings

The analyses performed for the proposed advanced operation mode, time-series and stochastic, consider the following control settings (see section 3.3.2):

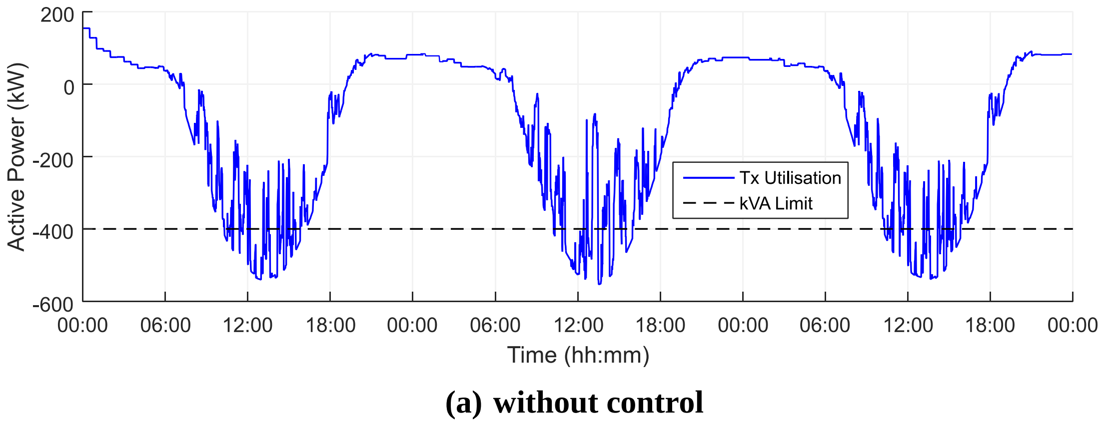
- $t_{peak} = 1\ p.m.$; aligned with the sun irradiance used in this study
- $T_C = 10\ hours$; less than the average daylight hours (15 hours)
- $SOC_{final}^{C} = 0.9\ (90\%)$; due to the upper reserve
- $SOC_{final}^{D} = 0.1\ (10\%)$; due to the lower reserve
- $V_{limit}^{upper} = 1.1\ p.u.$; French statutory limit
- $a = 0.98\ (98\%)$; slightly conservative to cater for cloud effects

6.4 Time-Series Performance

This section presents the time-series performance and the effects of residential-scale BES systems using the “normal” and proposed “advanced” operation mode. The analysis is performed for three consecutive sunny days on the real French LV network considering 70% of PV penetration. Load profiles for each customer are randomly selected and allocated based on the procedure described in section 4.3.2 for the days 15, 16 and 17 June 2014 (considered to have the lowest demand during summer). The PV systems are randomly allocated in the network based on the selected penetration level and assumed to be either 3kWp or 6kWp systems, sharing the same generation profile which considers June. For each 3kWp or 6kWp PV system a 10kWh or 20kWh BES system is allocated (as detailed in 6.2.1), respectively.

6.4.1 Normal Operation Mode

Figure 6-2 shows the transformer's utilisation level for the case (a) without and (b) with BES systems. Results clearly show that the adoption of BES systems using the normal operation mode does not bring any significant benefit in terms of reducing the transformer's utilisation level. Although the utilisation reduces significantly during early hours of the first day, BES systems fail to do that on the following days.



(b) with BES systems (normal operation)

Figure 6-2 Monitored power at the transformer

This is caused due to the two limitations stated previously (section 3.3.1.3) as most of the BES systems do not fully discharge overnight. As a result, the BES systems achieve full SOC very early in the day and, hence, are unable to reduce the reverse power flowing back to the substation.

Indeed, Figure 6-3, which shows the individual SOC of each household, validates the aforementioned statement as almost all BES systems achieve full SOC (90%) around midday (i.e., 12pm). Once the BES systems start discharging, the SOC reduces differently for each household as it depends on the corresponding household demand. The majority of the BES systems never completely discharge and, therefore, a significant volume of energy is still available in the batteries by the time the new charging period (following day) begins. This, forces the BES systems to reach full SOC even earlier the day after. The mean behaviour of the SOC, considering all BES systems and represented with a thick dashed black line in Figure 6-3, demonstrates that the SOC is varying only from 90% to 60%. This highlights the inability of this operation mode to fully utilise the BES system capacity.

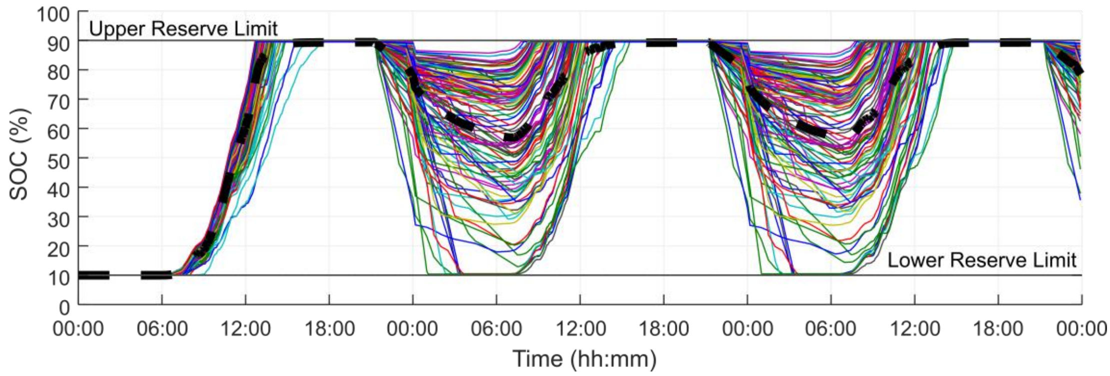
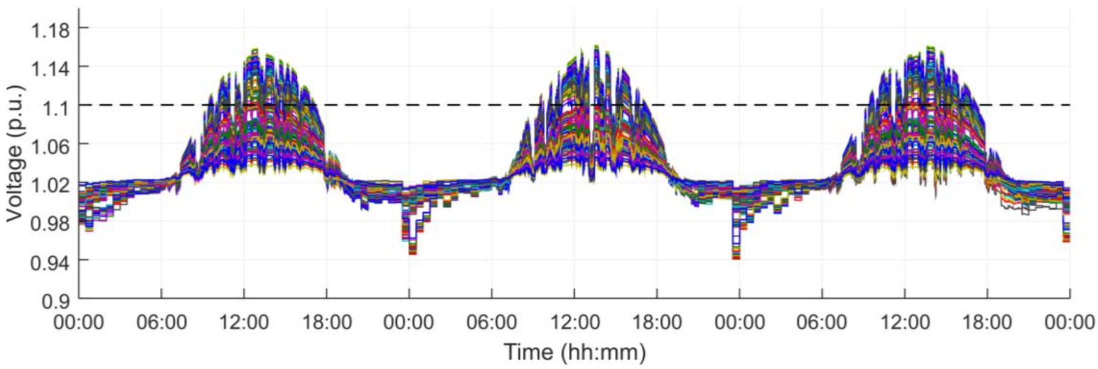
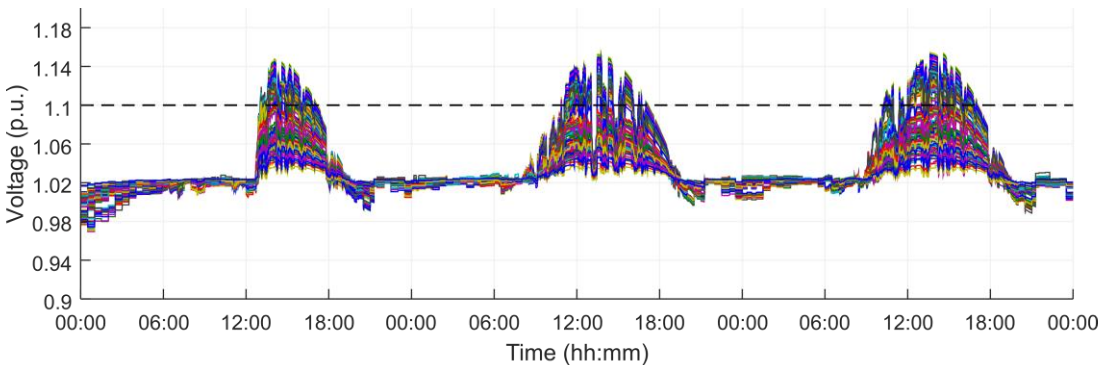


Figure 6-3 Individual SOC Profiles for all BES systems (normal operation)

More importantly, the performance described above also limits the ability of the BES systems to reduce potential voltage issues during midday where generation is at peak. To demonstrate this, Figure 6-4 presents the daily voltage profiles of all customers in the network for the case (a) without and (b) with residential-scale BES systems. Figure 6-4 (a), as expected, shows that most of the voltage issues occur during the peak generation period (i.e., 10am to 5pm). When BES systems are in place, Figure 6-4 (b) shows that during the first day, where BES systems are empty, it is possible to flatten the profiles (BES systems store all the excess of PV generation) until ~2pm where all BES systems reach full SOC. Crucially, due to the fact that full SOC is achieved very early, voltage profiles cannot be reduced during the peak generation period. This issue becomes even more critical the following days as the majority of BES systems start the next charging cycle with an average SOC of 60%. Hence, as Figure 6-4 (b) shows, the reduction of voltage profiles is insignificant (see 2nd and 3rd day around 9am to 12pm).



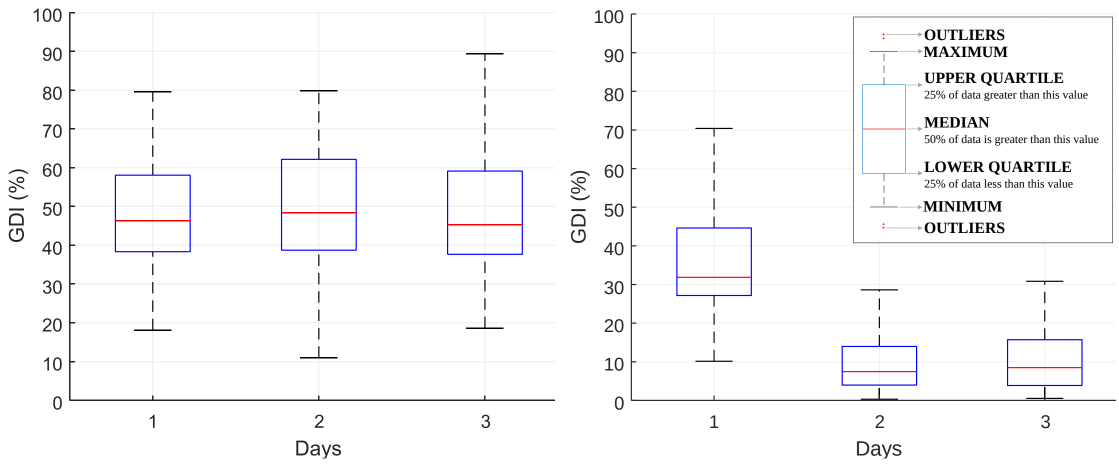
(a) without control



(b) with BES systems (normal operation)

Figure 6-4 Daily 1-minute voltage profiles of every customer

Although the aforementioned results highlight the drawbacks of the normal operation mode to assist in voltage and thermal management (i.e., DNO benefits), the results show that the customers (i.e., individual households) can reduce their grid dependency and, hence, their corresponding electricity bill. To visualise this, Figure 6-5 shows the GDI of all customers (boxplot representation) with PV system installations for the case (a) without and (b) with residential-scale BES systems. Considering the case where BES systems are not available, Figure 6-5 (a) shows that the median number of customers GDI is around 50% which means that almost 50% of their energy consumption is supplied by the substation and the other 50% by the local PV generation. However, considering the case with BES systems, Figure 6-5 (b) demonstrates that the GDI can reduce even more as additional energy can be supplied locally by the BES systems. For this particular analysis, it was found that the customers' GDI is reduced down to ~10% except the first day which is reduced slightly (~30%) as BES systems are empty during the early hours; hence, cannot supply energy. In summary, this specific example shows that during summer, the use of BES systems with normal operation can potentially help reducing customer electricity bills.



(a) without BES systems **(b) with BES systems (normal operation)**

Figure 6-5 GDI

Lastly, in terms of energy, Table 6-2 shows, for each day, the total energy imported in the LV network for the case without and with residential-scale BES systems, respectively. As expected, when BES systems are available in the network (excluding the first day were BES systems start empty), the energy imports are significantly reduced compared to the case without BES systems; most energy is now supplied locally.

Table 6-2 Network Energy Imports – BES Normal Operation

	Day 1	Day 2	Day 3
Without BES systems	864 kWh	799 kWh	871 kWh
With BES systems (Normal Operation)	721 kWh	229 kWh	302 kWh

6.4.2 Advanced Operation Mode

Using the same scenario as in the previous section, the time-series performance of the proposed advanced operation mode for residential-scale BES systems is investigated considering the real French LV network for the same three consecutive summer days with 70% of PV penetration level.

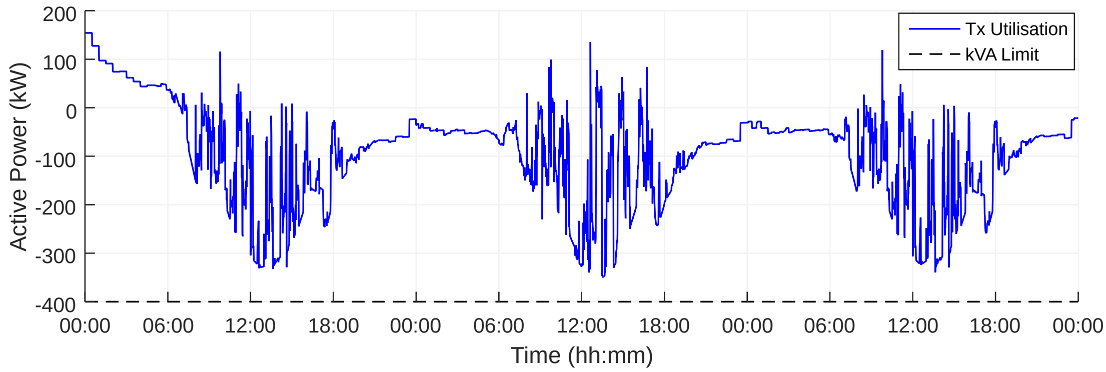


Figure 6-6 Transformer utilisation with BES systems (advanced operation)

Figure 6-6 shows that the proposed advanced operation mode significantly reduces the utilisation level of the transformer compared to the case with normal operation (see Figure 6-2). Although the advanced operation mode is not directly managing thermal issues, the nature of the progressive charging overcomes the limitation of reaching full SOC very early in the day and then allows charging throughout the whole period. Consequently, this method is able to significantly reduce the reverse power flows (due to the PV generation) and, therefore, keep the transformer's utilisation well below its thermal limit (i.e., 400kVA).

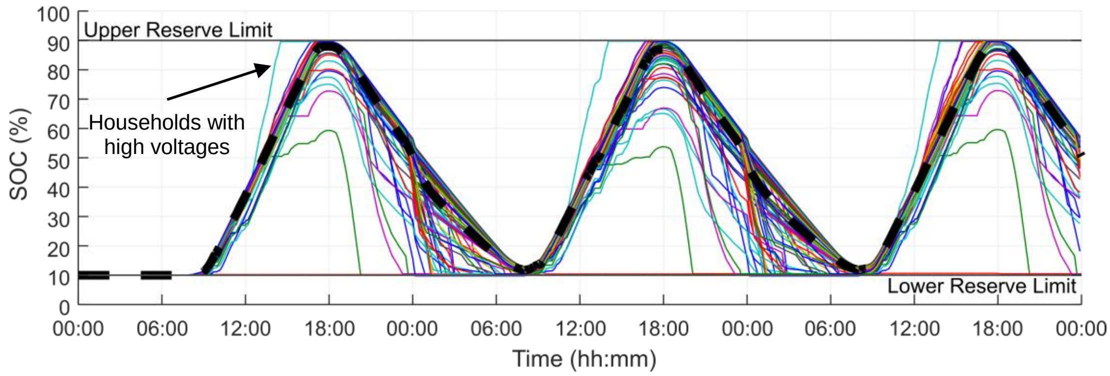


Figure 6-7 Individual SOC Profiles for all BES systems (advanced method)

Figure 6-7, which shows the individual daily SOC for each BES system in the investigated network, demonstrates the effectiveness of the proposed advanced operation mode to fully charge and discharge all BES systems by the end of each period (i.e., charging and discharging). In average, and compared to the results in section 6.4.1, the SOC profile (black dashed line) shows that the proposed advanced operation mode is able to fully utilise the whole storage capacity (from 10 to 90%) while having the same performance every day.

It is important to mention that some BES systems (e.g., cyan colour - indicated with arrow) become full earlier than the end of the charging period (i.e., 6pm). This is, in fact, the result of the voltage control, which is forcing the specific BES systems to charge with higher power rate in order to reduce the voltage at the corresponding connection point.

Similar behaviour can also be noticed during the discharging period where several BES systems become empty before the end of the period (i.e., 8am). This is because these systems are supplying customers with very large demand profiles and, therefore, the discharging power is very high, causing a fast decline of the SOC.

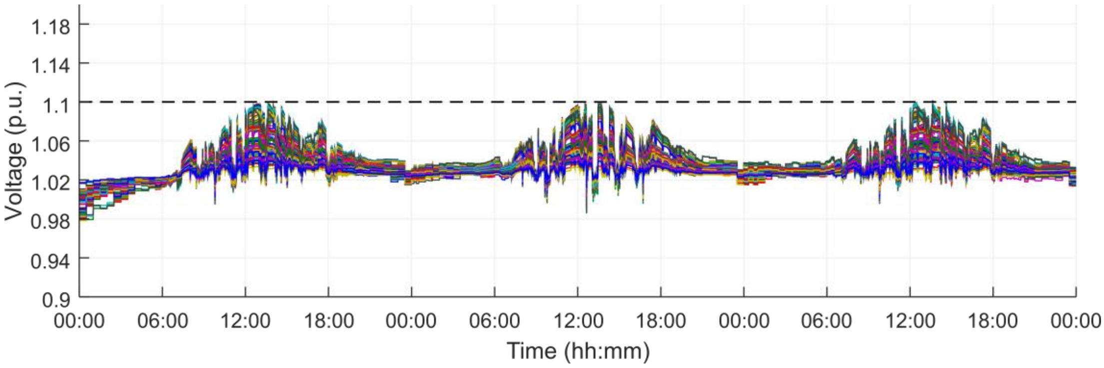


Figure 6-8 Customer Voltages with BES systems (advanced method)

In terms of voltage issues, results shown in Figure 6-8 demonstrate the effectiveness of the proposed advanced operation mode to keep all customer voltages below 1.1p.u (i.e., upper French statutory limit - black dashed line). The ability of the advanced operation to progressively charge throughout the whole charging period allows having enough storage capability by midday where most of the voltage issues occur (high irradiance) and, therefore, BES systems are able to increase their charging power rate to reduce voltage profiles. Additionally, it can also be noticed that the voltage profiles also become more flat even during the evening as power is locally supplied.

More importantly, from the customer side, Figure 6-9 demonstrates that the proposed advanced operation mode is significantly reducing customer's GDI which means that customers are becoming less dependent to the LV network as most of their demand is now supplied locally by the BES systems. Considering the median values (excluding the first day), the GDI is reducing down to ~2% (median) showing that, in general, most of the customers have a very low dependency to the grid which means significantly reduced bills.

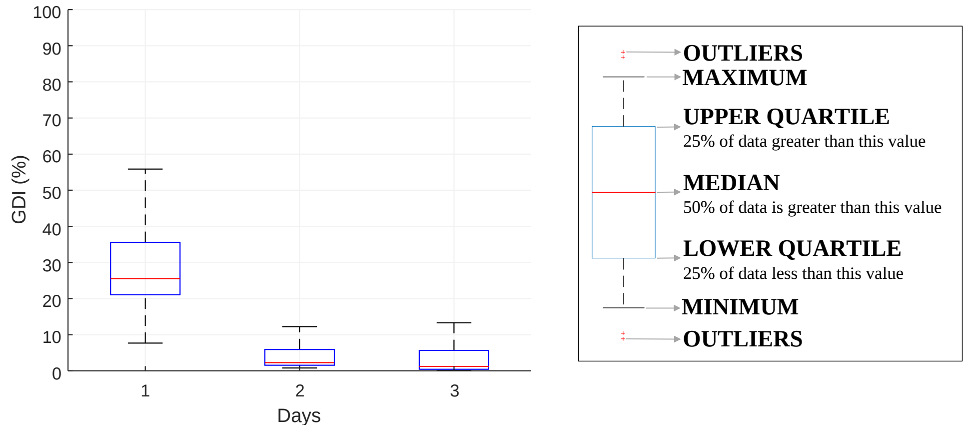


Figure 6-9 GDI with BES systems (advanced operation)

Table 6-3 Network Energy Imports and Exports – BES Advanced Operation

	Day 1	**Day 2**	**Day 3**
With BES Systems (Advanced Operation)	486 kWh	26 kWh	6 kWh

As a result of the above (low GDI), less energy is now required to be imported in the LV network by the secondary substation. Indeed, Table 6-3 shows that the energy imported to the LV network is significantly lower compared to the cases investigated in section 6.4.1. For example, only 26 and 6 kWh of energy is imported during the second and third day, respectively.

6.5 Stochastic Analysis

In this section, the proposed advanced operation mode for residential-scale BES systems is stochastically investigated on the real French LV network considering different penetration levels of PV systems during summer (i.e., lowest demand days, highest generation). The performance of the proposed mode is compared with the normal operation mode and with the case without residential-scale BES systems (only PV systems) adopting the Monte Carlo methodology described in section 4.5. This analysis presents and assesses the benefits obtained for both customers (i.e., increasing self-consumption, GDI) and DNOs (i.e., voltage and thermal management) when adopting the proposed method.

6.5.1 Voltage Issues

Similarly to the previous analyses, Figure 6-10 shows that without residential-scale BES systems (i.e., no control case in previous analyses), an average of ~10 customers might start facing voltage problems (i.e., EN 50160 non-compliant customers) at 40% of PV penetration, where this number increases to 120 at 100% of penetration.

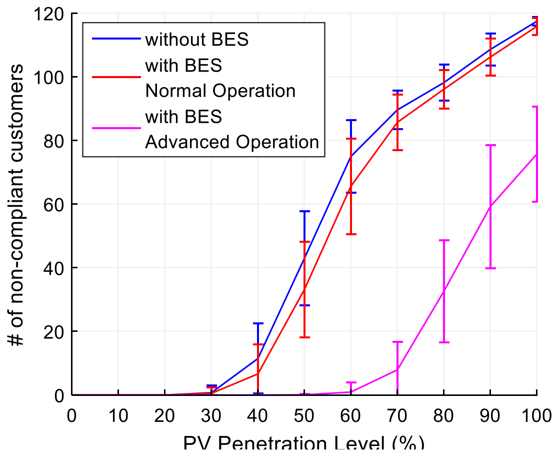


Figure 6-10 BES Systems - Voltage issues

When residential-scale BES systems are adopted with normal operation mode, is observed that, although slightly less customers experience voltage issues at each penetration level, the performance remains almost the same as the case without BES systems. This, which is also highlighted in the time-series performance (section 6.4.1) and discussed in 3.3.1.3, is due to the limitations of the normal operation mode where the BES systems reach full SOC very early (at or before midday); hence, voltage profiles cannot be reduced during the peak generation period.

However, a significant performance improvement is, however, achieved when residential-scale BES systems are adopted with the proposed advanced operation mode as almost no customer is affected by voltage issues until very high PV penetration levels (i.e., 60% onwards). Even at these high penetration levels, the number of EN 50160 non-compliant customers is significantly lower compared to the case without residential-scale BES systems. For example, in average only 10 and 35 customers are non-compliant at 70 and 80% of PV penetration levels, whereas at 90 and 100% penetrations the number is reducing from 110 and 120 down to 60 and 75, respectively.

Although these results demonstrate that a significant voltage management improvement is achieved with the proposed method, PV generation curtailment is still required at high PV penetration levels. This is due to the fact that at high penetration levels of PV voltage issues occur earlier during the morning (simultaneous generation of more PV systems) and BES systems are forced to charge at higher power rates; hence, become full before the end of the charging period and not able to reduce voltages after that.

Although the adoption of such high PV penetrations (i.e., above 50%) is not expected in the short term, these results highlight that residential-scale BES systems along with the proposed advanced operation mode can be an effective solution to manage voltage issues in LV networks while significantly increasing their hosting capacity.

6.5.2 Thermal Issues

Figure 6-11 and in Figure 6-12 show the transformer's and feeders' maximum utilisation level without (blue line) and with residential-scale BES systems adopting the normal (red line) and proposed advanced operation mode (magenta line).

As expected and previously demonstrated (time-series analysis, section 6.4.1), the stochastic analysis of the normal operation mode of residential-scale BES systems proves and highlights that the corresponding mode does not provide significant benefit in terms of thermal management. Although Figure 6-11 and Figure 6-12 show that the maximum utilisation of the assets slightly reduces with the corresponding operation mode, the reduction is not enough (about 5% at each penetration) to increase the network's hosting capacity.

On the other hand, the adoption of the residential-scale BES systems with the proposed advanced operation mode is able to significantly reduce the transformer's and feeders' maximum utilisation levels. As illustrated in Figure 6-11 the transformer's average maximum utilisation level (considering all Monte Carlo simulations) is always below 100% (except at 100% of PV penetration level where the transformer is slightly overloaded). The same effect is also noticed considering feeder utilisation levels (Figure 6-12) and, in particular, Feeder 2 which is the most loaded feeder. It is important to mention that these figures represent the average maximum utilisation level recorded throughout the day and it does not mean that the assets are always operating at these levels.

Although the proposed advanced operation mode is not directly managing thermal issues, results show that the reduction of reverse power flows, because of the BES charging period, is able to provide a satisfactory solution in terms of reduced thermal issues in LV networks and, hence, significantly increase the hosting capacity of LV networks.

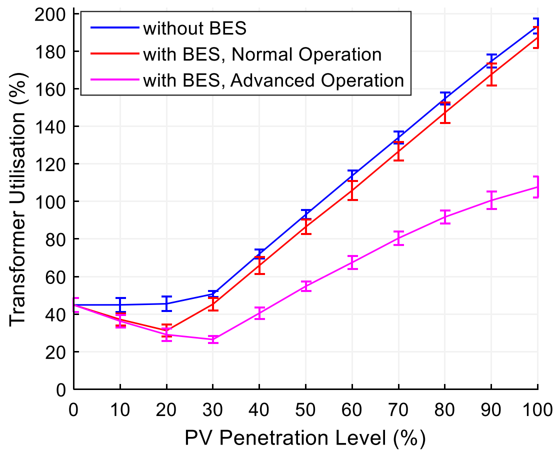


Figure 6-11 BES Systems - Transformer maximum utilisation level

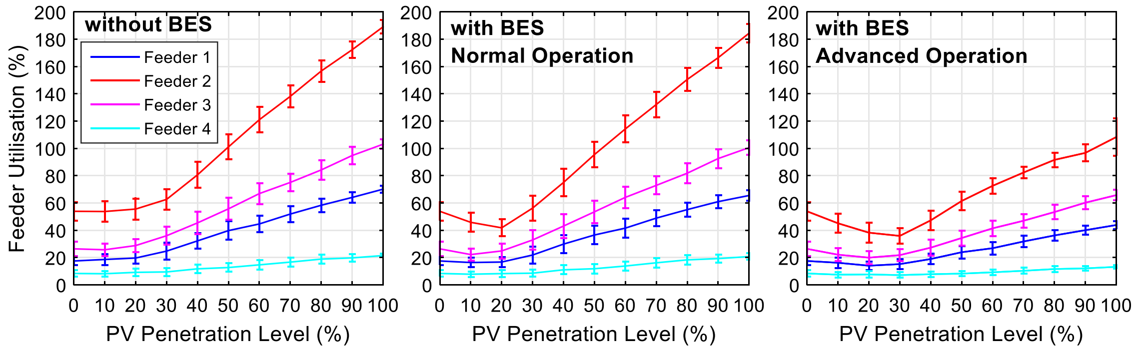


Figure 6-12 BES Systems - Feeders' maximum utilisation levels

6.5.3 Energy Metrics

In terms of the total energy produced by the residential-scale PV systems, Figure 6-13, which presents the average daily total active energy (kWh) produced by the residential-scale PV systems for each penetration level, highlights, as expected, that the adoption to BES systems (with either operation mode) does not result in any curtailment. The same performance (overlapped lines) is observed in all cases (i.e., without and with BES).

Clearly, these results, compared to the previous analyses, highlight that the adoption of residential-scale BES systems along with the proposed advanced operation mode can help increase the energy harvested by the PV generation while reducing the voltage and thermal issues; hence, increasing the hosting capacity of LV networks.

Regarding the energy losses, which can be seen in Figure 6-14, it is highlighted that the adoption of BES systems with either operation mode can help in reducing the network's energy losses. This can be explained as the result of the reduce power flows in the LV network due to the fact that BES systems are charging some of the excess of the PV generation. In addition, demand is now supplied locally instead of energy flowing from the substation to the customers.

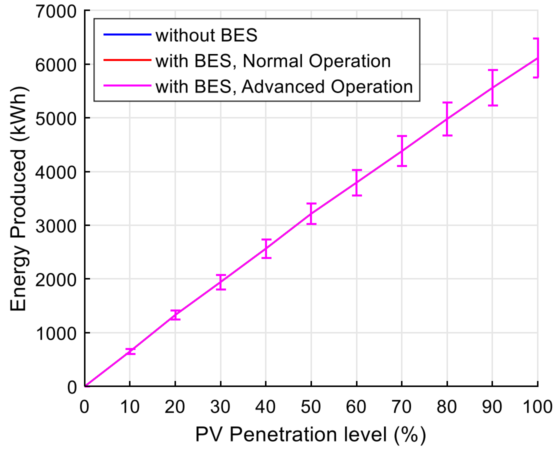


Figure 6-13 Energy Produced

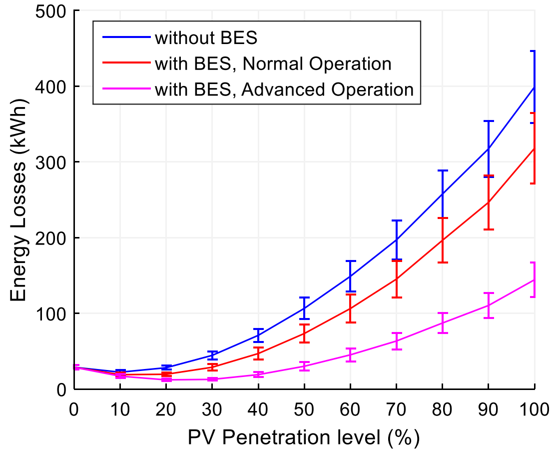


Figure 6-14 Energy Losses

In general, it is observed that the proposed advanced operation mode results in significantly lower energy losses compared to the normal operation mode. For example, the energy losses at each penetration level reduce by an average of ~20% when adopting the normal operation mode, while the adoption of the advanced operation mode results in a reduction of an average of ~65%. This is because the former (normal operation) fails to reduce the reverse power flow throughout the whole PV generation period (i.e., limitation of which BES systems reach full SOC before midday). On the other hand, the proposed advanced operation mode allows charging throughout the whole generation period and, hence, significantly reduces the amount of current flowing back to the substation.

6.5.4 Energy Imported

Figure 6-15 shows the average daily total energy imported to the LV network (at the MV/LV substation) considering the cases without and with residential-scale BES systems adopting the normal and advanced operation mode, respectively.

Interestingly, results show that without BES systems the amount of energy imported in the LV network is reducing almost with PV penetration level as a significant amount of energy is supplied by the PV generation locally. For example, the imported energy from 50% of PV penetration onwards almost reduces by 50%

(compared to 0% of penetration). However, the energy supplied, in such case, is limited only to the period when PV systems are generating and, hence, are able to supply the corresponding demand only during that period. Given that an important incentive to install PV systems is to increase the production and use of *"green energy"*, these results highlight that still almost 50% of the LV network demand has to be supplied by the substation. No matter the level of PV penetration as the *"green energy"* from PV systems can supply the corresponding demand only during the generation hours.

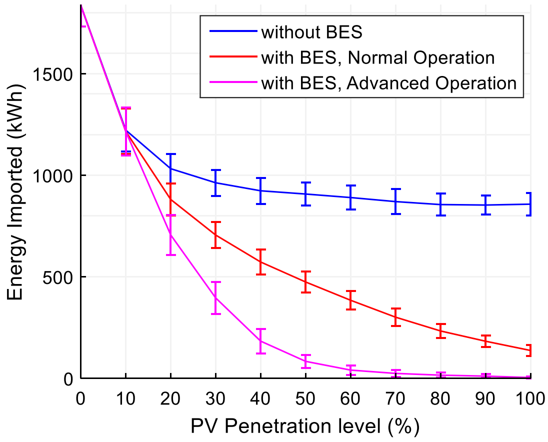


Figure 6-15 Energy Imported

However, the adoption of residential-scale BES systems, with either operation mode, significantly reduces the amount of energy imported by the LV network as they are able to store a significant amount of unused "*green energy"* and supply the household demand during the night where PV systems are not generating. It can also be highlighted that the imported energy significantly decreases with penetration levels. With higher PV penetrations the capacity of BES systems also increases (more 20kWh BES systems) and, hence, are able to supply a larger (or all) amount of the corresponding household demand.

Considering the normal operation mode, the imported energy reduces (compared to 0% of PV penetration level) by almost 14% at 20% of PV penetration and by 27 and 38% at 30 and 40% of penetration, respectively. This reduction continues to increase with penetration levels where at 100% the total energy imported reduces to almost 84% (compared to the case without BES systems).

Regarding the adoption of the proposed advanced operation mode, the total energy imported reduces even further as the BES systems always discharge based on the discharging power rate and, therefore, nearby households can also be supplied locally; hence, less energy is required from the substation. Indeed, as observed in Figure 6-15, by adopting the advanced operation mode, the imported energy at each penetration level reduces even more compared to the normal operation mode. For example, the imported energy reduces by almost 37% at 20% of PV penetration and by 62 and 80% at 30 and 40% of penetration, respectively. From 50% onwards, the energy imported almost reduces by 97% which means that almost all the demand in LV network is supplied locally by both the residential-scale PV and BES systems.

These results also highlight that there is a need to revise the way customers are charged in the future as the adoption of residential-scale BES systems will significantly reduce the energy imported and, therefore, reduce the income of DNOs (largely based on consumption).

6.5.4.1 Grid Dependence Index (GDI)

Considering the results shown in the last section, 6.5.4, where the imported energy is reducing for both cases without and with residential-scale BES systems (with either operation mode), it is expected that the households' GDI will decrease significantly as a significant volume of energy is supplied locally (i.e., PV generation, BES systems or both); hence, households can be less dependent from the substation. To explore this, Figure 6-16 statistically represents (boxplots) the average GDI of customers with PV system (with and without BES system) considering all Monte Carlo simulations and all investigated PV penetration levels.

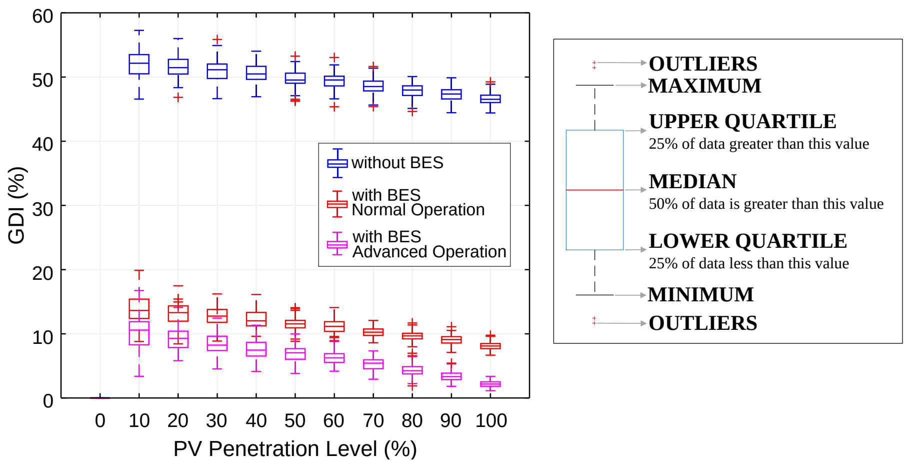


Figure 6-16 GDI

Indeed, considering the case without residential-scale BES systems, results are aligned with the findings in Figure 6-15, showing that almost half of the household demand is supplied locally by the PV generation. For example, the GDI is in average close to 50% for all penetration levels meaning that households with PV systems are only 50% dependant by the substation (i.e., their electricity bill can be assumed 50% less compared to the case without PV systems).

More importantly, as results demonstrate, households' GDI can be reduced even more when adopting residential-scale BES systems with either operation mode. For example, adopting the normal operation mode, the median GDI drops down to 15% at 10% of PV penetration level and this continues to reduce as penetration increases reaching 7% at 100% of penetration.

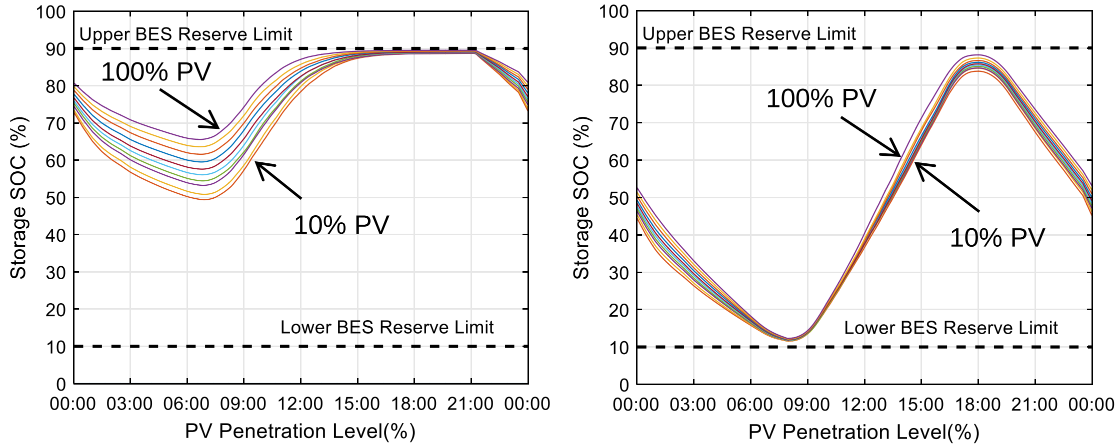
Nonetheless, the adoption of the proposed advanced operation mode shows that the GDI can reduce by 5% more at each penetration level. Considering this, the median value of the GDI drops down to 10% when 10% of PV penetration is assumed and this number reduces even more with higher penetration levels as BES systems with higher capacities (i.e., 20kWh) are considered. For example, the median GDI drops to 9% with 50% of PV penetration and continues to reduce to 5% and 2% at 70 and 100% of penetration, respectively.

Given the analysis above, it is clear that the adoption of residential-scale BES systems with the proposed advanced operation can significantly reduce customers' dependence on the grid and, therefore, their corresponding electricity bills.

6.5.5 State of Charge (SOC)

Figure 6-17 shows the average daily SOC profile of the residential-scale BES systems while adopting the (a) normal and (b) proposed advanced operation mode. The different line colours represent the daily average profile of each penetration level (from 10 to 100%).

As expected and previously highlighted (see section 6.4), results shown in Figure 6-17 (a) demonstrate the inability of the normal operation to fully utilise the whole storage capacity of the BES system as its average SOC is varying only from 50 to 90% (i.e., storage capability). This effect can be explained as the normal operation mode fails to fully discharge the BES systems until the next charging period. Consequently, the BES systems start to charge with a significant amount of energy already stored in their batteries. It is also important to mention that the storage capability reduces with higher penetration levels as bigger BES systems (20kWh) are installed, which might be significantly higher than the household's energy needs. Thus, a higher amount of energy remains in the battery at the end of the discharging cycle which forces the system to reach full SOC even earlier in the following day.



(a) Normal Operation **(b) Advanced Operation**

Figure 6-17 SOC

On the other hand, the adoption of the proposed advanced operation mode allows utilising the whole capacity (from 10 to 90% of SOC) of the residential-scale BES systems achieving almost the same excellent performance in all penetration levels. At the beginning of the charging period (i.e., 8am), the SOC is as required, equal to 10%, which allows for a charging headroom up to 90%. This provides the benefit to always start charging from the lowest available SOC point; hence reducing the risk of achieving full SOC very early during in day (one of the limitations identified in section 3.3.1.3). During the charging period, the SOC linearly increases and the BES system becomes full (90% of SOC) at the specified end of the charging period (i.e., 6pm). This proves that the proposed advanced operation mode can make use of the full BES system capacity and always store the maximum possible energy of the otherwise unused PV generation.

Once the discharging period begins (6pm), the opposite behaviour is noticed. The SOC linearly decreases until the end of the specified discharging period (i.e., 8am). Results show that the proposed method is able to fully discharge the BES systems (one of the drawbacks identified in section 3.3.1.3 allowing for a full charging headroom (i.e., 10 to 90%) in the next day.

Overall, results show that the proposed advanced operation mode can achieve an excellent performance in terms of the storage utilisation for all penetration levels.

6.6 Summary

The analysis performed in this chapter provides a quantitative assessment of the benefits when adopting residential-scale BES systems in combination with residential-scale PV systems in order to maximise customer benefits while managing voltage and thermal issues.

It is demonstrated that the adoption of residential-scale BES systems with a normal operation mode (control mode adopted by manufacturers) although provides significant benefits to the customers (i.e., reduced dependence to the grid) it does not provide any benefit to the DNO (i.e., voltage or thermal management). In addition the analysis highlighted the already mentioned important limitations (see section 3.3.1.3) of the normal operation mode where the:

- BES systems achieve full SOC before peak generation (i.e., PV impacts still occur around noon); and,
- BES systems start charging the excess of PV generation (early daylight) with a SOC already above the lower reserve (i.e., not adequately discharged overnight)

On the other hand, the proposed advanced operation mode was found to overcome the aforementioned limitations and, while still beneficial to the customers (i.e., reduced dependence to the grid, hence reduced electricity bills), it also allows managing voltage and thermal issues. The analysis demonstrates that the proposed operation mode can effectively eliminate all voltage issues up to high PV penetration levels (i.e., 60%) beyond which it can significantly reduce them. Although the proposed advanced operation mode does not directly manage thermal issues, it is proved that the reduction of reverse power flows, due to the charging period, is able to provide a satisfactory solution in terms of thermal issues in the corresponding test LV network.

Considering the customer benefits, the proposed advanced operation mode significantly reduces their dependence to the grid while still benefiting from the quality of service brought by the grid (e.g., supply always available). In general, without considering any capital and operational expenditures required for the uptake of residential-scale PV and BES systems, results mean that customers will potentially pay less electricity bills compared to the case where BES systems are not adopted.

In general, this analysis clearly demonstrates that the adoption of residential-scale BES systems with the proposed advanced operation mode can significantly help increasing the harvesting of PV generation (otherwise curtailed) while providing benefits to both customers and the DNO.

Chapter 7

Case Study Part 4: Simulation Analyses for LV OLTC-fitted Transformers

7.1 Introduction

This chapter investigates and presents a quantitative assessment of the benefits when adopting OLTC-fitted transformers with the proposed control logic in order to manage voltage issues in PV-rich LV networks. Its performance is assessed adopting two different levels of monitoring considering location (i.e., middle and end point of feeders) and four different control cycles (i.e., 1, 10, 20, 30-min). First the OLTC-fitted transformer adopted for the corresponding analyses is presented. Then, the time-series performance of the proposed OLTC control logic is assessed using the real French LV network. Lastly, its performance is stochastically investigated considering different penetration levels of residential-scale PV systems for different days in summer (i.e., lowest demand days), levels of monitoring and control cycles. Considering that the adoption of LV OLTC-fitted transformers only affects voltages (i.e., power flows remain the same), the following analyses discuss the performance of the proposed OLTC control logic only in terms of voltage issues and control actions (i.e., tap changes).

All the minute-by-minute time-series power flow simulations are performed in OpenDSS [144] and driven (using the COM Server) by MATLAB where all the proposed control algorithms are implemented.

7.2 Modelled LV OLTC-fitted Transformer

An LV OLTC-fitted transformer, is adopted to perform the corresponding analyses in order to assess the performance of the proposed OLTC control logic that aims in managing voltages in PV-rich LV networks. The OLTC considers a range of +/-8% of voltage with 2% per tap, i.e., 9 tap positions in total, according to available manufacturer specifications [145]. Assuming that the voltage at the primary of the

MV/LV transformer is the nominal line-to-line voltage (i.e., 20,000V), the busbar voltages corresponding to different tap positions are shown in Table 7-1.

It should be noted that the specific transformation ratio is selected in order to provide the flexibility to have tap positions that can provide the maximum possible range of voltage level within the voltage statutory limits (+/-10% of nominal voltage, in France).

Table 7-1 Voltage regulation of the modelled LV OLTC-fitted transformer

Transformer Tap position	MV	LV		Vbase = 400V
	L-L (V)	L-L (V)	L-N (V)	V (p.u)
9 (+8%)	20000	368	212.5	0.92
8 (+6%)	20000	376	217.1	0.94
7 (+4%)	20000	384	221.7	0.96
6 (+2%)	20000	392	226.3	0.98
5	20000	400	230.9	1
4 (-2%)	20000	408	235.6	1.02
3 (-4%)	20000	416	240.2	1.04
2 (-6%)	20000	424	244.8	1.06
1 (-8%)	20000	432	249.4	1.08

For example, with the corresponding OLTC setup and assuming that the voltage at the primary of the transformer is at nominal value (20kV) and there is no loading, the lowest line-to-neutral voltage at busbar would be around 212.5V (tap position 9) and the highest line-to-neutral voltage at busbar would be 249.4V (tap position 1).

The embedded OLTC model in OpenDSS allows the control of the device by providing a new voltage target at every control cycle. This voltage target, either to manage the busbar or a remote point, is then automatically translated into an internal tap control command to achieve the desired value. In the proposed control logic (section 3.4.2), the required tap changes are carried out in the next time step (e.g., the next minute, assuming 1-min control cycle).

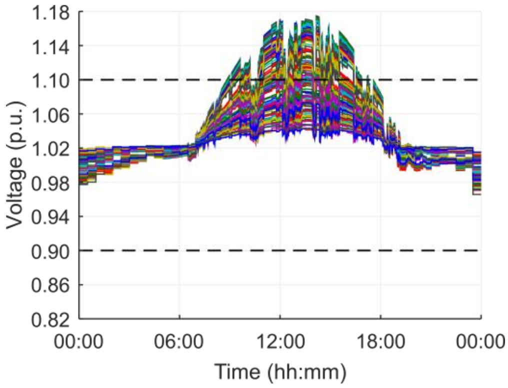
It is also important to highlight that the corresponding OLTC bandwidth is set to 2.5% (+/-1.25%), which means that a new tap position can be triggered if the monitored phase voltage at the busbar is higher or lower than 1.25% of the set-point voltage (voltage target). As a default setting, the OLTC model in OpenDSS monitors the busbar voltage in phase A.

7.3 Time-series Performance

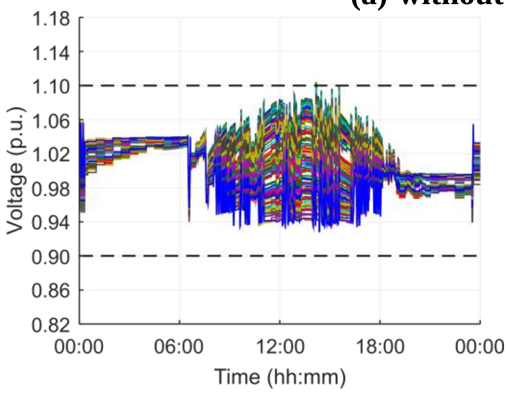
Considering the same deterministic single case scenario used in section 5.3.1, the time-series performance of the proposed OLTC control logic is illustrated in this section adopting remote monitoring at the end of each feeder (considered to be the location of the farthest customer) and two different control cycles (i.e., 1 and 10-min).

Figure 7-1, which presents all customer voltage profiles for the case (a) without and with (b) 1 and (c) 10-min OLTC control, illustrates the performance of the proposed control logic. Considering either control cycles, it can be observed that during the period where voltages rise (around 8am), the tap position of the OLTC, which is shown in Figure 7-2, increases to reduce the busbar voltage and, hence, bring the monitored voltages within the statutory limits. Indeed, the analysis shows that the proposed OLTC control logic with either control cycles is able to bring and keep all customer voltages within the French statutory voltage limits ($0.9\,p.u. \leq V \leq 1.1\,p.u.$). Similarly, when the PV generation starts to reduce, and hence the voltages (around 5pm), the OLTC control logic is increasing the voltage target which so that the remote end voltage will be will not violate the lower limits. Indeed as observed in Figure 7-2, the tap position starts to reduce from around 5pm in order to increase the voltages. When the sun settles down (no PV generation) tap position four is eventually reached (see Figure 7-2, b), which corresponds to 1.02 p.u. of voltage target; the middle point of voltage statutory limits and also the V_{ref} of the OLTC controller.

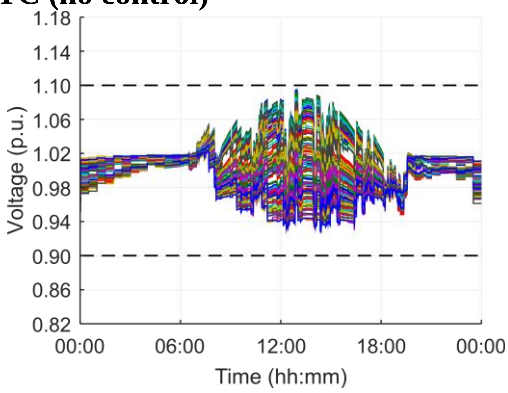
Results also point out that the overall performance is influenced by the control cycle length. For example, the adoption of 1-min control cycle, although achieves the desired goal (i.e., voltage management), it results in a significantly high number of tap changes (i.e., 204 for this case) as an action is triggered almost every minute due to the intermittent behaviour of the demand and PV generation (e.g., cloud effects). This however can lead to the OLTC wear and tear [124] and, as a consequence, increase maintenance costs. Nonetheless, increasing the control cycle to 10 minutes, the performance in terms of voltages remains the same (as the 1-min control cycle) while significantly reducing the number of tap changes (i.e., 20 for this case, Figure 7-2, b). In general, as the control cycle increases, control actions (i.e., tap changes) are expected to reduce due to the fact that the controller uses the average monitored voltages of the last *x* minutes (10 minutes in this case) which in turn smooths the intermittent behaviour of the PV generation (e.g., sudden voltage spikes or drops due to cloud effects).



(a) without OLTC (no control)

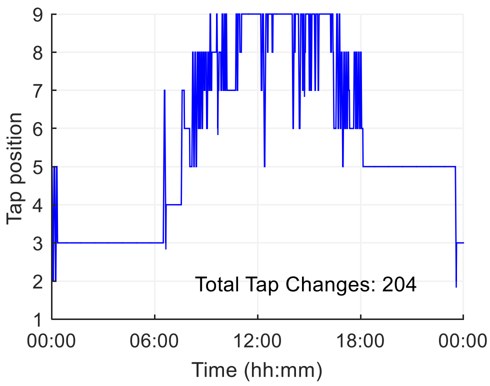


(b) with OLTC, 1-min control

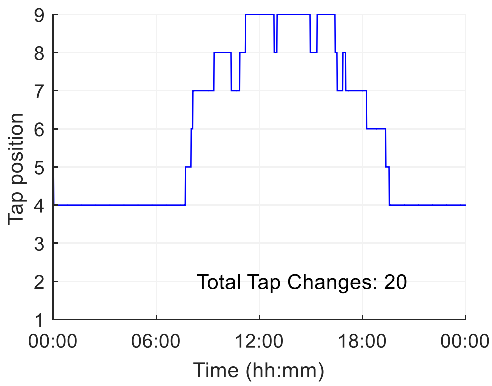


(c) with OLTC, 10-min control

Figure 7-1 Daily 1-min voltage profiles of customers, OLTC control logic



(a) with OLTC, 1-min control



(b) with OLTC, 10-min control

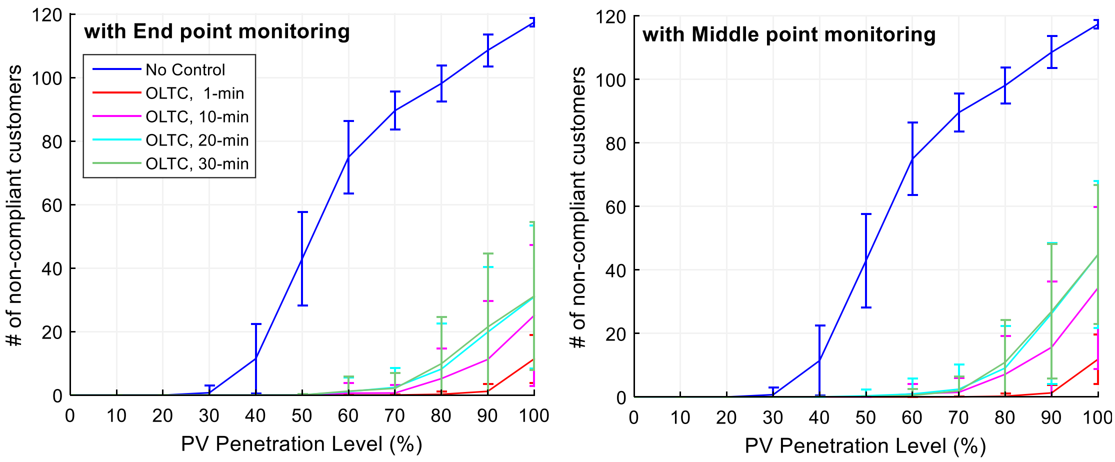
Figure 7-2 Tap positions

7.4 Stochastic Analysis

Following the time-series performance, the proposed OLTC control logic is stochastically investigated on the real French LV network considering different penetration levels of residential-scale PV systems during summer. Its performance is assessed adopting two different levels of remote monitoring (i.e., middle and end point of each feeder) and four different control cycles (i.e., 1, 10, 20, 30-min) by applying the Monte Carlo methodology described in section 4.5.

7.4.1 Voltage Issues

The analysis highlights that the proposed OLTC control logic can achieve an excellent performance in terms of voltage management. In general adopting the proposed OLTC control logic with any of the adopted remote monitoring points (i.e., middle or end) and control cycles (i.e., 1, 10, 20, and 30 minutes), allows shifting the network's hosting capacity to 50% of penetration without experiencing any issues.



(a) End remote monitoring **(b) Middle remote monitoring**

Figure 7-3 OLTC Control - Voltage issues

From that point (i.e., 50% of penetration) forward, the performance is slightly affected by the corresponding adopted control cycle length (i.e., 1, 10, 20 and 30-min) and the level of remote monitoring (i.e., middle and end point of each feeder). For example, considering the end monitoring, it is observed that the shorter the control cycle length, the better the voltage performance. More specifically, Figure 7-3 (a) shows that at 100% of PV penetration, adopting 1-min control cycles with remote monitoring at the end of each feeder, the number of EN 50160 non-compliant customers reduces from an average of almost 120 to 10. This number, however, increases to an average of 25 customers when adopting 10-min control cycles and goes to 30 customers with 20 and 30-min control cycles.

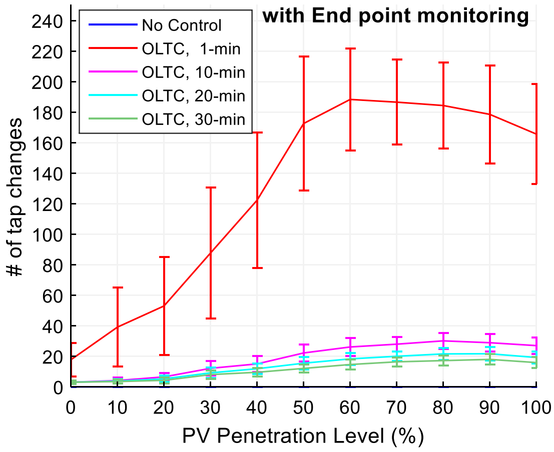
Taking into account the level of remote monitoring, Figure 7-3 demonstrates that the control logic performs better with remote monitoring at the end of each feeder. This is due to the increased visibility (closer to the most critical customers - those connected at the far ends) which in turn allows a more accurate calculation of the required voltage target. For instance, at 100% of PV penetration the case with monitoring only at the middle of each feeder resulted in an average of 15 non-compliant customers more than the case with end monitoring. Hence, the end monitoring can be considered as the most effective approach to support the operation of the OLTC.

Overall, the analysis highlights that the proposed OLTC control logic allows increasing the hosting capacity of the LV network whilst also reducing the magnitude of voltage problems across all penetration levels.

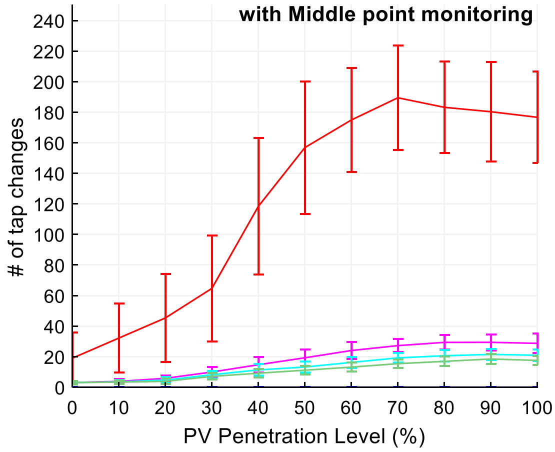
7.4.2 Control Actions

Figure 7-4 (a) and (b) show the average number of daily tap changes triggered for each control cycle (i.e., 1, 10, 20, 30-min) and PV penetration level considering remote monitoring at the end and middle of each feeder, respectively. In general, the level of monitoring does not influence the performance as, in average, the same number of tap changes is required for both cases; hence, the discussion here considers only the results obtained and shown in Figure 7-4 (a).

Control cycles, on the other hand, can clearly be seen as significantly influencing the number of tap changes. As also highlighted in the time-series performance (see section 7.3), the number of tap changes is indeed decreasing with longer control cycles. For example, 1-min control cycles lead to an average of 120 and 164 tap changes for 40% and 100% of PV penetrations, respectively. These figures are significantly reduced to an average of 10 and 20 when 20 and 30-min control cycles are adopted, respectively. More importantly, assuming an average of 20 tap changes per day, the resulting annual number of tap changes, in this case, represents only around 1% of the maximum number that, according to manufactures, the LV OLTC-fitted transformer can withstand [145]. Moreover, the ability of the proposed OLTC control logic to keep a low number of tap changes while effectively managing voltage issues can potentially keep maintenance costs low.



(a) End remote monitoring



(b) Middle remote monitoring

Figure 7-4 OLTC Control – Number of daily tap changes

Finally, considering that the number of non-compliant customers slightly increases with longer control cycles, the 20 and 30-min control cycles can be considered as a trade-off between the number of tap changes and EN 50160 non-compliant customers. Nonetheless, this setting should ultimately be based on the requirements of the DNO.

7.5 Summary

The analysis performed in this chapter provides a quantitative assessment of the benefits when adopting the proposed OLTC control logic LV OLTC-fitted transformers to manage voltage issues in PV-rich LV networks. It is shown that the adoption of the proposed OLTC control logic with limited monitoring (i.e., end point of each feeder) can efficiently shift the occurrence of voltage issues at a higher penetration level, beyond which the number of customers facing voltage issues can significantly reduce (compared to the case without control).

Furthermore, it is highlighted that the location of remote monitoring points in the feeders and the control cycle length play an important role in the performance of the control logic. The analysis demonstrates that having monitors only at the end of each feeder and adopting 20 or 30-min control cycles can be the most effective approach to limit tap changes (i.e., less impact on the OLTC utilisation) while minimising the number of customers that could be affected by voltage issues.

7.6 Comparison of Investigated Control Schemes

Table 7-2 summarises and compares the technical benefits (i.e., voltage and thermal management) of the proposed control schemes investigated in this Thesis, along with different implementation aspects (i.e., potential required investments, effects on customers).

Table 7-2 Control Schemes Summary

Control Method	Technical Benefits		Potential Required Investments		Effects on Customer
	Voltage	Thermal	Monitoring	New Assets	
Volt-Var	Yes (Limited)	No (Increases)	No	No*	No
Volt-Var (over-rated)	Yes	No (Increases)	No	Yes (Over-rated Inverters)	Yes (Higher Inverter Cost)
Volt-Watt	Yes	Yes (Indirect)	No	No*	Yes (Curtailment)
CTC	Yes (Indirect)	Yes	Yes (Substation)	Yes (Comms)	Yes (Curtailment)
CTC + Volt-Watt	Yes	Yes	Yes (Substation)	Yes (Comms)	Yes (Curtailment)
BES (Normal)	No	No	No	No*	Yes (Reduced Bills)
BES (Advanced)	Yes	Yes (Indirect)	No	No*	Yes (Reduced Bills)
OLTC	Yes	No	Yes (End Points)	Yes (OLTC, Comms)	No

*Assumed that the corresponding PV inverters/BES systems are already installed by the customers.

In terms of technical benefits, Table 7-2 shows that the least beneficial control schemes are the Volt-Var with normal PV inverters and the adoption of BES systems with normal operation. These control schemes provide limited (or no) benefits to the voltage and thermal management. Although, the adoption of the Volt-Var control with over-rated inverters can help managing voltage issues, it entails higher inverter costs to the end customers.

On the other hand, adopting the Volt-Watt control, voltage issues can directly be managed while indirectly reducing potential thermal issues; however, this requires some of the PV generation to be curtailed, leading to reduced profits for the PV owners. Assuming that residential-scale BES systems are in place, the adoption of the proposed advanced operation for BES systems can also bring similar benefits (i.e., direct voltage and indirect thermal management), yet, without curtailing energy.

Furthermore, it provides benefits not only to the DNO but also to the customers (i.e., reduced electricity bills). Nevertheless, the corresponding control performance might be influenced by the corresponding battery size. Similarly, the adoption of LV OLTC-fitted transformers with the proposed control logic can also provide significant benefits in voltage management without affecting customers (curtailment of PV generation). However, some investment is required for the installation of the OLTC-fitted transformer, monitoring devices and communication infrastructure.

Ultimately, the combined centralised thermal and decentralised voltage control (i.e., CTC+Volt-Watt) brings the most benefits in terms of technical issues as it directly manages both voltage and thermal issues. Despite the excellent performance achieved with the corresponding control scheme, which also entails PV generation curtailment, some investment in monitoring (limited) and communication infrastructure is required.

Although an economic assessment (future work) is essential to have a well–rounded comparison, this table allows comparing and identifying the most adequate control scheme based on the technical requirements (e.g., voltage and/or thermal management) and potential investment. Moreover, it is highlighted, that, a trade-off should always be made between the required solution (e.g., voltage and/or thermal management), the corresponding investment (e.g., monitoring, communications) and the effects on customers.

Chapter 8

Conclusions and Future Work

8.1 Introduction

This chapter provides first an overview of the research and main literature gaps. Then, the contributions of this Thesis are presented along with a summary of conclusions. Lastly, potential improvements and future work are discussed.

8.2 Research Area Overview and Main Gaps

The cost reduction in residential-scale PV systems along with the incentives rolled out in several countries around the world and in particular the EU, are the two main factors for the rapid adoption of residential-scale PV systems in LV distribution networks. However, the increased penetration of residential-scale PV systems is likely to lead to technical issues such as voltage rise and thermal overloads of the most important and expensive network assets (i.e., transformer, feeder cables).

These issues, in turn, limit the ability of LV networks to accommodate larger volumes of low carbon technologies, in particular, residential-scale PV systems. Consequently, to facilitate the connection of larger volumes without the need for expensive and time-consuming network reinforcements, DNOs should move from passive to active LV networks, where controllable devices and LCTs are actively managed to solve technical issues. Emerging LCTs (i.e., residential-scale PV and BES systems) offer numerous controllability options (i.e., generation curtailment, reactive compensation, power reduction by storing energy) which can be used in either a “centralised” (i.e., transformer as the ‘hub’) or “decentralised” (local) way to manage voltage and thermal issues. Even more mature technologies, commonly used in higher voltage levels, can be adopted in LV networks. Technologies like OLTCs can be adopted at secondary distribution substations (i.e., MV/LV) and actively managed to alleviate voltage issues.

Despite the fact of active LV networks being a relatively new concept, the literature review carried out in this Thesis highlights that there is an increasing research interest in this area and, in particular, the control of residential-scale PV and BES systems. Although several active network management schemes have been proposed in the literature aiming to increase the hosting capacity of PV-rich LV networks, the majority are:

- <u>Based on complex optimisation techniques which require expensive communication infrastructure and full network observability which are currently not available in LV networks.</u> Considering the extensiveness of LV networks around the world, the installation of monitoring devices (to provide network visibility) might not be economically feasible. In addition, the adoption of optimisation methods might lead to significant computational times and increase the risk of not converging to a solution as the size of the optimisation problem significantly increases with network size and number of control variables. Consequently, it is essential to explore the extent to which already available devices, information and limited monitoring (i.e., secondary distribution substation) could be used to augment the network visibility.

- <u>Limited to deterministic load flow analyses that consider specific PV penetration levels.</u> Some others, even more limited, consider only several snapshots of load and generation profiles. These analyses are not suitable considering the intermittent behaviour of load and PV generation. Hence, to cope with the corresponding uncertainties and to truly understand the impacts on the electricity infrastructure to which the PV systems will connect to, as well as potential solutions, stochastic approaches must be adopted. More importantly high granularity (e.g., scale of seconds and minutes) time-series demand and generation profiles are essential to allow realistic modelling and time-series analyses.

- <u>Focused on managing voltage issues only, ignoring the fact that thermal issues might also occur with high PV penetration levels.</u> Therefore, integrated solutions that consider and manage simultaneously both voltage and thermal issues need to be developed.

- <u>Assuming PV inverters with ratings that can be high enough (i.e., oversized inverters) to maintain the full solar output (kWp) and the requested vars.</u>

However, commercially available residential-scale PV inverters might have limited capability to inject or absorb the required reactive power (i.e., vars) in periods of high power output (i.e., sunny weather condition). Hence, realistic studies that consider this important limitation are required to understand the extent to which reactive compensation through residential-scale PV systems can help managing voltage issues.

8.3 Thesis Main Contributions

Considering the gaps in literature, the main contribution of this Thesis is the proposal and development of innovative, practical and scalable active network management schemes that use limited network monitoring and communication infrastructure to actively manage:

- Residential-scale PV systems;
- Residential-scale BES systems, and;
- LV OLTC-fitted transformers.

The adoption of the proposed active network management schemes which make use of already available devices (i.e., PV inverters, BES systems), information and require limited network monitoring (i.e., at the secondary distribution substation) allows making the adoption of the proposed schemes, in LV networks, more practical and cost-effective. In addition, their generic nature allows being easily adapted to control any other low carbon technology that can support active or reactive power control.

In addition, to tackle the challenges related to this research (i.e., lack of realistic LV network modelling with high resolution time-series analyses), this Thesis contributes by considering a fully modelled real residential French LV network (three-phase four-wire) with different characteristics and number of customers. Moreover, realistic (1-min resolution) daily time-series household (from smart meters) and PV generation profiles are considered. A stochastic approach (i.e., Monte Carlo) is also adopted to cater for the uncertainties related to household demand as well as PV generation and location.

The following subsections present the details of the main contributions.

8.3.1 Management of Residential-scale PV Systems

Decentralised Voltage Control (Volt-Watt). It is demonstrated that a universal, single set of Volt-Watt settings is possible to be identified with the proposed method as the most adequate to effectively manage voltage issues, regardless the penetration, in a given LV network. This brings benefits to the DNO as it increases the scalability of the corresponding control method due to the fact that these settings are universal for all PV inverters, require a one-off setup (e.g., on the installation day) and are valid for any PV penetration.

Decentralised Voltage Control (Volt-Var). The limitations and drawbacks adopting such a control method, with commercially available residential-scale PV inverters, are demonstrated for the first time. Findings show that the benefits of this control approach are minimal due to the limited reactive capability of PV inverters at peak generation periods, where voltages are higher. This allows DNOs to take more informed decisions when adopting decentralised voltage control with reactive compensation (i.e., Volt-Var).

Centralised Thermal Controller. An innovative and scalable centralised control logic which bridges the gaps in the literature (e.g., adoption of complex optimisation techniques, requirement of extensive network monitoring, not scalable, etc.) is developed and proposed in this Thesis. The proposed control logic aims to manage thermal overloads in PV-rich LV networks (for any penetration) while using limited network observability (i.e., substation measurements only). The proposed control logic, which its performance is successfully assessed considering different PV penetration levels (i.e., 0-100%), offers significant benefits to DNOs as it does not require the installation of remote monitoring points and reduces the need of costly communication infrastructure. More importantly, its generic nature, allows to be deployed and work on any PV-rich LV network while the performance is expected to be the same as the proposed method will always curtail the amount of energy required to keep the utilisation of assets within limits.

Combined Centralised Thermal and Decentralised Voltage Control. To provide a complete active network management aiming to solve both thermal and voltage issues at any PV penetration level, this Thesis proposes the combination of the centralised thermal controller with the decentralised voltage control (i.e., Volt-Watt). Unlike other solutions that are not easily implementable (due to complex optimisation algorithms, increased network visibility, expensive communication infrastructure), the proposed control method offers a more cost-effective solution requiring limited network observability. Again, as previously mentioned the generic nature of the proposed method, allows to be deployed and work on any PV-rich LV network.

8.3.2 Management of Residential-scale Battery Energy Storage Systems

For the first time, an advanced operation mode that provides benefits both to the customer (i.e., increased self-consumption) and the DNO (i.e., voltage and thermal management) is proposed for residential-scale BES systems. The proposed operation mode, which can be programmed on residential-scale BES systems, offers the advantages of the decentralised control approach thus requiring no communication infrastructure. Based on local measurements (i.e., inverter connection point) the advanced operation mode can progressively charge/discharge the BES system in a way that increases the customer's self-consumption while effectively eliminating all voltage issues up to high PV penetration levels beyond which it can significantly reduce them. The decentralised and generic nature of the proposed operation mode makes it replicable on any PV-rich LV network; however, it should be highlighted that the overall performance might be influenced by the size of the installed BES systems. For instance, although smaller sizes of BES systems will still bring benefit to the customers (i.e., reduced energy bills) they might not bring enough benefits to the DNO (i.e., voltage and thermal management) due to their limited storage capability.

8.3.3 Management of OLTC-fitted LV Transformers

A scalable and adaptive OLTC control logic that aims in managing contrasting voltages issues, rise (due to the presence of generation) and drop (due to loads) is proposed in this research. Compared to traditional OLTC control approaches (i.e., fixed voltage target) that do not consider the diversified voltage levels among different feeders (due to uneven penetration of LCTs, load unbalance, etc.), the proposed method allows the automatic update of the voltage target (at the busbar) according to network conditions while using limited network observability coming from critical remote monitoring points (i.e., feeders' end points). Crucially, this provides the significant benefit of easily adapting to network changes (i.e., additional installation of PV systems or loads) without the need of reconfiguring OLTC settings. The proposed OLTC control logic found to be effective in eliminating all voltage issues up to high PV penetration levels beyond which it can significantly reduce them.

8.4 Conclusions

The following subsections present the specific findings and knowledge gained from the analyses performed in this Thesis, considering the proposed active network management schemes.

8.4.1 Residential-Scale PV systems

A summary of the main findings and knowledge gained from the analyses performed considering the proposed active management schemes for residential-scale PV systems is presented below.

8.4.1.1 Decentralised Voltage Control

The benefits of adopting a decentralised voltage control is investigated in section 5.2 using the Volt-Var and Volt-Watt control functions and considering different control set-points for each control function. The following findings are obtained:

1. **Volt-Var Analysis**

   - **Normal rated inverters**

     - Voltage rise problems cannot be solved due to the limited reactive power capability of the normal PV inverter during high generation periods i.e., the rated kVA power is almost reached.

     - The absorption of reactive power increases the current flowing in the network. As a result the utilisation level of the assets increases which might lead to the overloading of the transformer and/or feeder cables.

- **10% over-rated inverters**
  - The application of Volt-Var control with over-rated inverters can provide a significantly better voltage management without the need of curtailing any generation. However, oversizing the inverters entails higher costs to the end customers which might not be willing to cover.
  - Although the adoption of over-rated inverters achieves better performance in terms of voltage management, it leads to even higher levels of asset utilisation (compared to normal inverters). This finding, which is not covered in the literature, allows DNOs to take more informed decisions when adopting decentralised voltage control with reactive compensation.

2. **Volt-Watt Analysis**

- This method found to be more effective in managing voltages (compared to the Volt-Var). Although this allows increasing the network's hosting capacity, it comes with the expense of curtailing some PV generation; thus potentially reducing the profits of the PV owners.
- It was demonstrated that a single Volt-Watt curve can be identified for a given network as to provide a trade-off between voltage issues and the required volume of curtailment. This finding allows increasing the scalability of the corresponding method as these settings are universal for all PV inverters and require a one-off setup (e.g., on the installation day).
- Although this control function is not directly managing thermal issues, it can also help reducing the utilisation of the assets, thus dealing with another important technical issue that might occur in PV-rich LV networks.

8.4.1.2 Centralised Thermal Controller (CTC)

The performance of the proposed centralised thermal controller is investigated in section 5.3. The following findings are obtained:

- The proposed centralised thermal controller is an effective solution to manage and solve thermal issues while indirectly reducing the number of customers experiencing voltage issues in PV-rich LV networks.

- Although control cycles do not significantly influence the overall performance of thermal management, it is highlighted that the shorter the control cycle, the better the performance. This, however, could potentially lead to higher number of control actions (i.e., PV signals) which might cause operational challenges (e.g., in communication).

- Findings highlight that a specific control cycle can be identified as a trade-off control setting between the number of control actions (i.e., PV signals) and operation performance (in terms of thermal and voltage issues).

8.4.1.3 Combined Centralised Thermal and Decentralised Voltage Control

The performance of the proposed combined centralised thermal and decentralised voltage control is assessed in section 7.3.3. The following findings are obtained:

- The adoption of the proposed combined thermal and decentralised voltage control provides a robust active network management in PV-rich LV networks, as it effectively eliminates all technical issues (both voltage and thermal) regardless the PV penetration level. This can be a potential solution for DNOs to efficiently manage both thermal and voltage issues and hence accelerate the transition towards active LV networks.

- As expected, in order to solve both voltage and thermal issues, slightly more energy is curtailed compared to the other investigated control methods. This however, allows accommodating higher number of LCTs in LV networks without the need of costly network reinforcements, thus accelerating the transition towards an eco-friendly low carbon environment.

8.4.2 Management of Residential-scale BES systems

The analysis performed in section Chapter 6 provides a quantitative assessment of the benefits obtained when adopting residential-scale BES systems in combination with residential-scale PV systems in order to maximise customer benefits while managing voltage and thermal issues. The following findings are obtained:

- The adoption of residential-scale BES systems with a normal operation mode although provides significant benefits to the customers (i.e., reduced dependence to the grid) it does not provide any benefit to the DNO (i.e., voltage or thermal management).
- The following limitations of the normal operation mode were highlighted:
    - BES systems achieve full SOC before peak generation (i.e., PV impacts still occur around noon); and,
    - BES systems start charging the excess of PV generation (early daylight) with a SOC already above the lower reserve (i.e., not adequately discharged overnight).
- The proposed advanced operation mode overcomes the aforementioned limitations and while still beneficial to the customers (i.e., reduced dependence to the grid, hence reduced electricity bills) it also allows managing voltage (directly) and thermal (indirectly) issues.
- The proposed operation mode can effectively eliminate all voltage issues up to high PV penetration levels beyond which it can significantly reduce them.
- The proposed advanced operation mode significantly reduces customers' dependence to the grid (hence reduced electricity bills) while they still benefit from the quality of service brought by the grid (e.g., supply always available).
- The adoption of residential-scale BES systems with the proposed advanced operation mode can significantly increase the harvesting of "green" energy (otherwise curtailed), coming from PV generation, while providing benefits to both customers and DNO. This in turn allows accommodating even higher number of LCTs in LV networks, accelerating that way the transition towards an eco-friendly and low carbon environment.

8.4.3 Management of LV OLTC-fitted LV Transformers

Chapter 7 presents a quantitative assessment of the benefits when adopting OLTC-fitted transformers with the proposed control logic in order to manage voltage issues in PV-rich LV networks. The following findings were obtained:

- The adoption of LV OLTC-fitted transformer with the proposed control logic regardless the adopted monitoring point and control cycle can effectively shift the occurrence of voltage issues at a higher penetration level; beyond which the number of customers facing voltage issues can significantly reduce.
- Findings highlight that the location of remote monitoring and the control cycle length play an important role in the performance of the control logic.
  - The shorter the control cycle, the better the voltage performance and the higher the number of tap changes.
  - The closer the remote monitoring to the last customer the better the voltage performance.
- The analysis demonstrates that having monitors only at the end of each feeder and adopting longer control cycles can be the most cost-effective approach (i.e., less monitoring devices) to limit tap changes (i.e., less impact on the OLTC utilisation; reduced wear and tear hence less maintenance costs) while minimising the number of customers that could be affected by voltage issues.

8.5 Future Work

Although research objectives, defined at the beginning of this research, have been successfully achieved in this Thesis there are still areas in which this work can be enhanced and further developed.

8.5.1 Seasonal Analyses and different representative LV networks

This work focused on multiple summer daily scenarios (different demand and PV profiles) given that they could result in higher technical impacts. However, to better assess the performance of the proposed active network management schemes, multiple seasons could also be investigated so as to produce a more meaningful year-long performance analysis. This will allow DNOs identifying the most adequate and cost effective control scheme able to provide voltage and thermal management throughout the year. In addition, considering the adoption of BES systems, seasonal analysis will also enable customers understanding the overall year-round benefits might gain with the adoption of residential-scale BES systems.

Similarly, to determine the most effective control scheme, that brings most benefits, analyses could also be carried out on different representative LV networks, as a future work.

8.5.2 Different BES systems and controls

This work considers only one type (i.e., lithium), make (i.e., Tesla PowerWall) and two sizes (i.e., 10 and 20kWh) of residential-scale BES systems. However, considering the wide range of BES systems available in the market and the continuous development of this technology, the analysis could potentially consider different battery types, makes and sizes of residential-scale BES systems to assess the performance of the proposed advanced operation mode in a more diverse scenario.

The adoption of reactive compensation through BES systems could also be investigated as a potential solution to manage voltage issues in PV-rich LV networks. This, however, would require the adoption of inverters that are able to support such operation; hence increasing the corresponding costs, that customers might not be willing to pay.

8.5.3 Economic Assessment

An economic assessment considering both the investment and operational costs of the proposed active network management schemes could be considered as a future work. An economic assessment compared with the traditional network reinforcement costs will allow understanding how economically feasible (or not) the proposed schemes are. Potential savings that might be achieved (or not) adopting the proposed schemes (instead of reinforcement) will enable DNOs take more informed decisions when adopting active network management schemes. Moreover, the economic assessment of the proposed schemes can identify the most cost-effective scheme that allows managing technical issues (in PV-rich LV networks), and potentially help in accelerating the transition towards active LV networks.

8.5.4 Consideration and combination of other LCTs

This Thesis has considered only two residential-scale LCTs (PV and BES systems) whereas other emerging technologies such as electric vehicles (EVs) could also be considered. In addition, the potential advantages or disadvantages resulting from the mix of these technologies could be investigated. Such scenarios (mix of technologies) will allow to truly understanding the benefits of adopting BES systems in combination with other technologies. For instance, the excess of PV generation stored in the BES systems during the day can potentially support not only the household demand during the night but also, if required, charge the connected EV.

8.5.5 Comparison with Optimal Solution

To understand the extent to which the proposed schemes provide an effective active network management and achieve adequate performance, the current research could be enhanced, for instance, by performing a comparison with an ideal optimization framework driven by an AC Optimal Power Flow (OPF). Such analysis can provide important insights on how far the outcomes of the proposed schemes are from the optimal solution. These insights could potentially highlight (or not) the practicality and scalability of the proposed schemes. For instance, a comparison of the proposed combined thermal and decentralised voltage control with the optimal solution will highlight the optimal amount of energy that needs to be curtailed as well as the number of control actions required in order to eliminate voltage and thermal issues.

8.5.6 Combination of Proposed Active Network Management Schemes

With respect to the active network management schemes proposed in this Thesis, a further development to allow additional penetrations of low carbon technologies in LV networks is the combination of some of the proposed schemes. For example, the adoption of the centralised thermal controller in coordination with the LV OLTC-fitted transformer could potentially enhance the flexibility of LV networks and, therefore, allow higher penetrations of low carbon technologies. In terms of energy curtailment, such combination could potentially achieve less generation curtailment (compared to the proposed centralised thermal and decentralised voltage control) as the LV OLTC-fitted transformer manages voltages without affecting the PV generation (as opposed to the case with Volt-Watt).

The proposed OLTC control logic could also be investigated in combination with the residential-scale BES systems adopting the proposed advanced operation mode. Considering the fact that the residential-scale BES systems can effectively eliminate voltage issues up to a specific PV penetration level, the LV OLTC-fitted transformer can potentially alleviate voltage issues beyond that.

A more sophisticated decentralised controller that could control both residential-scale PV and BES systems could be developed based on the proposed advanced operation mode for residential-scale BES systems and the reactive capability (i.e., Volt-Var) of PV systems. The decentralised controller could essentially instruct the PV systems to absorb reactive power in moments where the advanced operation mode of BES systems alone is not enough to keep the voltage within limits. The adoption of such scheme, will allow catering for potential voltage and thermal issues without the need of curtailing “green” energy (produced by PV systems). More importantly, the decentralised nature of this approach will not require any communication infrastructure.

In line with the above, a fully decentralised control scheme could also be investigated combining the decentralised Volt-Var and Volt-Watt control to address voltage issues while giving priority to the Volt-Var control that does not lead to generation curtailment. Coordination (i.e., ensuring Volt-Var priority) could be achieved by adequately specifying Volt-Var and Volt-Watt curves such that only the former acts up to specific voltages where the latter acts once the voltage has reached a specific value. In addition, such combination might increase the ability of residential-scale PV systems to absorb reactive power during high sun radiations as the parallel operation of the Volt-Watt control will potentially reduce the inverter’s active power output, hence allowing it to absorb more reactive power.

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