NEW STRATEGIC PLANNING GUIDELINES FOR URBAN MEDIUM-VOLTAGE GRIDS

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New Strategic Planning Guidelines for Urban Medium-Voltage Grids

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Preface

This dissertation was achieved during my work as a research assistant at the Chair of Power Systems Engineering in the University of Wuppertal. Therefore, I would like to thank everyone who contributed to achieving this work, either on the professional level or on the personal level.

First, I would like to praise God Almighty for guiding me so far in this life.

Secondly, I would like to thank Professor Markus Zdrallek for offering me the opportunity to do my research at the University of Wuppertal and for the guidance and supervision during the course of my PhD. His constructive feedback, technical expertise, and friendly manner have encouraged me to complete the work at hand.

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On a personal note, I sincerely thank my parents, who strongly supported me in every step along the way. Without their untiring efforts, encouragement and motivation, this work would not have been concluded. Equally, I thank my siblings for supporting me in this journey.

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Wuppertal, 2023
Shawki Ali

Abstract

The current catastrophic climate change pleads for a rapid energy transition from traditional combustion-based energy sources to electricity. This energy transition is driven by elements of the energy transition that utilise either electricity or renewable energy as an energy source for operating. Among these elements lies the focus on electric vehicles, heat pumps and distributed generation specifically photovoltaic systems.

With the world population concentrated in urban areas, the elements of the energy transition are expected to have a widespread in urban areas. For long years, the urban grids currently supplying these urban areas have been steadily developing along with the urban growth. However, the widespread and rapid penetration of electric vehicles, heat pumps and photovoltaic systems, for which no historical data is available, pose a challenge for distribution system operators. This energy transition pushes many urban grids to their limits of operation. Even though the whole distribution grid with the three main voltage levels is affected by the energy transition, the medium-voltage grids are particularly affected. Therefore, solutions to overcome this challenge are urgently needed to guide the distribution systems operators on how to navigate their grids during this transition. In this context, the dissertation in hand addresses the above-mentioned challenges through a systematic approach to the elements of the energy transition.

Firstly, the general framework conditions of these elements are analysed with a focus on the conditions relevant to grid planning. Furthermore, their future development in terms of development scenarios is investigated. At this point, the expected development of each element of the energy transition is determined.

Afterwards, the methodology of the strategic grid planning is developed. This methodology converts the analysed framework conditions and the development scenarios into load and feed-in values that can be modelled in the grids. Based on this modelling, the future supply and generation tasks of the grids are mapped. Consequently, the grid limits are identified. In the case of a violation, possible conventional and innovative planning measures are proposed.

Subsequently, a clustering algorithm is applied to a dataset of medium-voltage grids to determine representative urban medium-voltage grids. The developed methodology of the strategic grid planning is applied to these representative grids, thus resulting in several planning alternatives. These planning alternatives are assessed technically as well as economically.

Finally, a set of generally valid planning guidelines specifically tailored for urban medium-voltage grids are presented. These planning guidelines are methodologically deduced based on the assessed results of the strategic grid planning methodology for the chosen representative urban medium-voltage grids.

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1 Introduction

The world is going through an unprecedented challenge. The worldwide combustion of fossil fuels produces greenhouse gases that get trapped in the atmosphere [1]. This increase in greenhouse gases is causing catastrophic climate change over the last decades. Hence, a need for curbing climate change arises.

For combating climate change, cities and urban areas are central players in numerous sustainability strategies. Cities and urban areas are centres of social interaction and human consumption. Globally, approximately 54 % of the world's population currently lives in cities. These account for 80 % of added value, but also consume 78 % of the primary energy demand and produce 70 % of all greenhouse gas emissions [2].

The combustion of fossil fuels is the main energy source for several sectors, such as mobility, heating, and electricity production [3]. By replacing fossil fuels as an energy source with an environmentally friendly energy source, such as wind and solar energy, worldwide greenhouse gas emissions can be reduced. The shift from the fossil fuel-based energy sector to a low-emission energy sector is referred to as the "Energy Transition". The main drivers for the transition are the electrification of the mobility and heating sectors, as well as replacing fossil power plants with renewable electricity production.

1.1 Challenges of the Energy Transition in the Grids

The energy transition represents an unprecedented challenge for the power grids, with the electrification of almost all sectors of the economy being the main driver of it. Consequently, the power grids are facing a paradigm shift in their supply and generation tasks [4], [5]. The electrification of the mobility and heating sector can be achieved through Electric Vehicles (EVs) and Heat Pumps (HPs) respectively. Whereas, the decarbonisation of electricity production is currently pursued by increasingly integrating Distributed Generation (DG) from renewable energy sources like wind or photovoltaic. Henceforth, the technologies EVs, HPs, and DGs are referred to as the elements of the energy transition and the power grids simply as grids.

The elements of the energy transition enforce two contradicting influences on the grids. On one hand, the EVs and the HPs increase the supply task by introducing more loads into the grids. On the other hand, the DG strains the grid on the generation side as they impose a non-traditional load flow situation on the grid. These two contradicting influences impact the grids on all levels starting from the transmission grids down to the distribution grids. Whereas the transmission grids face the collective impact of the elements of the energy transition, the distribution grids are often the first level of incorporating these elements. With cities and urban areas being the centre of energy consumption, EVs, HPs and DG need to be integrated into urban areas.

Even though in urban areas, most of the elements of the energy transition are going to be connected to the low-voltage (LV) grid, the medium-voltage (MV) grid needs to be investigated too to ensure their successful integration. At the MV level, several factors affect the grid. Since a MV grid supplies several downstream LV grids, it must incorporate a consolidated large number of EVs, HPs and DG units. The collective impact of these units requires complex analysis and modelling on the MV level. This influence adds a further degree of complexity to investigating the MV grids.

Generally, the grids are dimensioned to fulfil the existing supply task through conventional power generation. The integration of the elements of the energy transition pushes the grids into an unprecedented load and generation situation. This grid situation represents uncertainty for the distribution system operators (DSOs) that need to be investigated through grid planning. Although grid planning is a well-established activity within DSOs, the lack of historical data for the new technologies, namely, EVs, HPs, and DG, intensifies the uncertainty of grid planning for the DSOs.

Since these technologies are still developing, their general framework conditions need to be researched and concretized. Moreover, their integration in terms of development scenarios into the urban areas, specifically into the grids, remains unpredictable and needs to be specified.

In addition to the general framework conditions and the development scenarios of the elements of the energy transition, a consistent grid planning methodology is required by DSOs to ensure a steady, safe operation of the grid. The planning methodology should include how to transform the development scenarios of the corresponding grid area regarding EVs, HPs, and DG into load and generation units in the individual grids. These load and generation units need to be modelled with suitable power values. Moreover, the planning should propose different alternatives to reinforce the grid. With the necessity of comprehensive grid reinforcements, innovative technologies, such as Load Management (LM) can be utilised as an alternative to conventional grid reinforcements. However, the potential of innovative technologies as a grid reinforcement measure requires further investigation.

The above-mentioned factors emphasize the necessity for new strategic Planning Guidelines (PGs). Based on an analysis of the impact of the energy transition on the MV grids and investigating different approaches to the grid reinforcements, PGs are deduced. The introduced PGs should enable the DSOs to successfully integrate the elements of the energy transition into their urban grids. In addition to being consistent, the PGs derived from the findings of the aforementioned work are valid so that they can be applied to German urban MV grids and can be adopted for any urban MV grid with grid characteristics similar to the investigated representative MV grids.

1.2 Related Work and State of the Art

The topic of strategic grid planning has been widely investigated and established in the literature. [6] covers the task of grid planning starting with the basic principles of grid planning and with economic and optimisation techniques for power grids. Then, it continues with the concrete grid planning steps beginning with load forecasting and then introducing the various measures for expansion planning. [7] discusses the power grids elaborately in which the different power grid components are listed and explained in detail. It introduces–at that time–relatively new technologies such as DG. Even though there are several more references discussing grid planning in detail, such as [8] and [9], a few of them consider the load development of EVs and HPs as well as DG in terms of Photovoltaic (PV) systems simultaneously.

One of the early publications that discuss the integration of EVs into power grids is [10]. It investigates the impact of different penetration levels on the power grid. [11]–[14] elaborate on the current state of the art of the different types of EVs, EV battery technologies, and charging technologies. [11] continues with investigating the impact of EVs on the power grid demand collectively for a whole country. Continuing on the grid impact of EVs, publications such as [15]–[18] investigate the consequences of the EV load on exemplary power grids. The results show the impact on power grid parameters such as the voltage profile and the equipment loading. Even though these investigations emphasise the violations happening to the grid, the required planning measures to solve these violations are not elaborated. In addition to EVs, the impact of HPs on the power grids needs to be investigated.

The available publications have covered the HPs in different ways. [19], [20] investigate the impact of HPs on the grid by generating load profiles for the HPs. Consequently, they overlap these load profiles with other load or generation units in the grid to investigate the impact on an urban and a suburban grid in [19] or on the total electricity demand of a country in [20]. A detailed study of the steady-state and the transient effect of HPs on an exemplary grid is done in [21]. To curb the impact of HPs on the grids, several control strategies are investigated in [22]–[24] which in turn reduce the expected grid violations. Moreover, the combination of a HP and a PV system in households has been comprehensively explored in articles such as [25], [26]. Furthermore, the combined impact of EVs and HPs on the distribution grids has been investigated in [27], [28]. Even though the aforementioned references have dealt with the topic of HPs and EVs, or HPs and PV, their combined impact on several urban MV grids needs to be investigated.

With the increase in the load demand in the power grids, innovative technologies are developed to reduce the required grid reinforcement measures. One of the developed innovative technologies is LM. [29] gives an overview of load management techniques with a focus on incentive-based and dynamic pricing-based LM. However, it does not investigate the influence of LM on the required grid reinforcement measures.

This concern has been tackled in [30], [31] where the LM is deployed to reduce the peak load, enhance the voltage profile and minimise power losses in a test grid with several integrated residential LV grids. Several other control strategies for LM with a focus on EVs have been investigated in the literature [32]–[34]. Although these studies explore different LM techniques, the potential of load regulation of HPs along with the charging infrastructure requires further analysis and investigation. Furthermore, the potential of the regulation of the public charging infrastructure can be theoretically investigated.

Another innovative technology is Energy Storage (ES). An overview of ES and its potential to reduce bottlenecks in the grid is presented in [35]. Even though these studies investigate the potential of the innovative technologies either for exemplary grids or on a large-scale deployment, the advantages of these technologies in comparison to the conventional grid expansion measures need further examination. Furthermore, the conditions for the economic and practical application of these technologies are missing.

The next step is the application of the findings from the above-mentioned literature to the grids. Even when these findings are demonstrated, PGs are desirable to apply these findings directly to grid planning. Preliminary PGs are mentioned in [36]–[39] with regard to DG. However, these PGs do not consider the development of EVs and HPs in urban areas.

1.3 Objective and Structure of the Work

Based on the literature review given in section 1.2, this work complements the published findings with the following new additions. In the field of grid planning, the above-mentioned literature is complemented by:

1. considering separate development scenarios,
2. identifying representative MV grid models from a MV grid database, and
3. developing and applying an assessment model for the results of the grid planning.

To fully investigate the possible development of the elements of the energy transition in the MV urban grids, the dissertation

4. simultaneously considers several charging powers for the charging infrastructure of EVs, while differentiating between private and public charging points, as well as charging points at customer substations, and
5. analyses HP models with different power ratings.

In the context of innovative planning technologies, further investigations of modelling the innovative planning technologies and their potential in remedying grid limit violations are performed. These investigations include:

6. the modelling and application of LM systems considering different load regulation variants as well as several LM layouts depending on the available measurement and information infrastructure, and
7. the modelling and application of ES systems,

Finally, the findings and the analysis are consolidated by

8. deducing generally valid PGs for urban MV grids.

In tackling these new findings, Chapter 2 (p. 7) starts with a technical overview of the considered elements of the energy transition. The chapter covers the general framework conditions and the development scenarios of not only EVs and HPs but also DG, specifically PV systems. Furthermore, it provides a brief overview of other available technologies for the energy transition, such as power-to-gas and power-to-heat stations.

Chapter 3 (p. 21) explains the methodology of strategic grid planning in detail. The methodology begins with the modelling of the considered load types, ranging from traditional household and industrial loads to the charging infrastructure of EV and HP loads, as well as the modelling of PV systems. Afterwards, the permissible grid limits are given. In case of a limit violation, the chapter presents solutions in terms of conventional and innovative planning measures and technologies. Within the innovative planning technologies, the modelling of LM and ES is explained. Two assessment models are introduced to evaluate the different Planning Alternatives (PAs).

The following Chapter 4 (p. 67) aims to apply the methodology of the strategic grid planning. Firstly, representative MV grid models are selected by performing grid clustering. For three selected MV grids (inner-city, city and suburban), the load development and the resulting PAs are demonstrated. Moreover, a technical and economic assessment of the performed grid planning is presented.

Based on the methodology for the strategic grid planning and its application, Chapter 5 (p. 95) deduces the PGs for urban MV grids and for cross-voltage level grid planning. Moreover, a decision path for the MV grid planning is presented. To validate the PGs, a sensitivity analysis is then performed and a critical discussion of the method and the PGs is performed.

The final Chapter 6 (p. 125) concludes the work done by summarising the main findings and developed methods.

The presented work in terms of assumptions, methods, models, and applications can be valid for all urban regions with urban and demographic characteristics similar to the German characteristics. Furthermore, the proposed PGs can be valid for all MV urban grids with a grid topology similar to the MV grid topology given in section 3.1 (p. 21) and with a development matching the development of the elements of the energy transition described in Chapter 2 (p. 7).

2 Elements of the Energy Transition in the Grids

To investigate the impact of the elements of the energy transition on MV grids, a detailed understanding of their framework conditions and development is necessary. Hence, this chapter describes the framework conditions of the elements of the energy transition relevant for the grid planning along with their development scenarios. The chapter starts with the elements causing a load increase in the grid, namely, EVs and HPs. Afterwards, the DG is specified in detail. Finally, an overview of further elements of the energy transition is given.

2.1 Fundamentals of Electric Vehicles[1]

EVs have been developing over the past years with different modes of operation, ranging from hybrid EVs to plug-in EVs [41]. With the focus on grid planning, it is considered that the plug-in EV mode of operation corresponds to the highest electric demand in the grid. As hybrid EVs rely also on the combustion of fossil fuels as a secondary or an alternative source of energy, it can be concluded that their electric demand from the grid is lower than that of the plug-in EV.

The charging infrastructure used to charge the EVs is eventually the equipment that is relevant for the grid planning. The charging infrastructure consists of individual charging stations, which can contain one or more Charging Points (CPs).

Within this work, a CP is defined as: "a power outlet at which only one EV can be charged". A CP represents the individual component, which collectively builds up that charging infrastructure. Depending on the location of the installation of the CP and consequently the accessibility to the CP, two types of CPs are defined, namely, private Charging Points (prCPs) and public Charging Points (puCPs). The following definitions, which are taken from the German regulation on charging points, are used as a basis for differentiating between prCPs and puCPs:

Publicly accessible charging point (Public charging point):

"In the context of this regulation, a charging point is publicly accessible if it is located either on a public road space or on a private land, provided that the parking space of the charging point is accessible from an undefined group of people or by a group of people that can be identified according to general characteristics." [42]

Privately accessible charging point (Private charging point):

"When the access to a charging point is granted only to a group of people that are already or can be determined, it is not identified as a publicly accessible charging point within the context of this regulation." [43]

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[1] The findings in this section have already been published in [40].

2.1.1 General Framework Conditions of Electric Vehicles

Similar to any other component connected to the grid, the EVs have a set of framework conditions to be considered in order to analyse their integration into urban areas. Since the EVs are not directly connected to the grid, the conditions investigated in this context focus on the CPs in terms of technical and economic framework conditions.

Based on the constantly updated data on the puCPs from the German Federal Grid Agency (FGA) [44], Figure 2.1 shows an analysis of the development of the puCPs in the previous 14 years (2009 – December 2022) in Germany. The figure differentiates the development in terms of the number of puCPs for certain ranges of nominal charging power P_{CP}. Since the installed puCPs do not follow specific charging power values, ranges for the charging power are given.

By analysing the development of the number of puCPs, the results show that within the last four years (2019 to 2022) approximately 50,000 new CPs were installed into the German grids. This development of the CPs exhibits a drastic acceleration in integrating the puCPs into the grids compared to previous periods, which is expected to continue in the future. The expansion of the CPs into the grids is investigated in terms of scenarios for EVs presented in section 2.1.2 (p. 10).

Moreover, Figure 2.1 shows the detailed development of the installed charging power over the previous thirteen years. A further assessment of the charging powers shows that puCPs with a charging power of P_{CP} = (11; 22] kW[2] are the highest share of installed puCPs. Furthermore, the number of puCPs with $P_{CP} > 22$ kW have been highly increasing in recent years. Hence, it can be assumed that puCPs with charging powers $P_{CP} > 11$ kW will steadily increase.

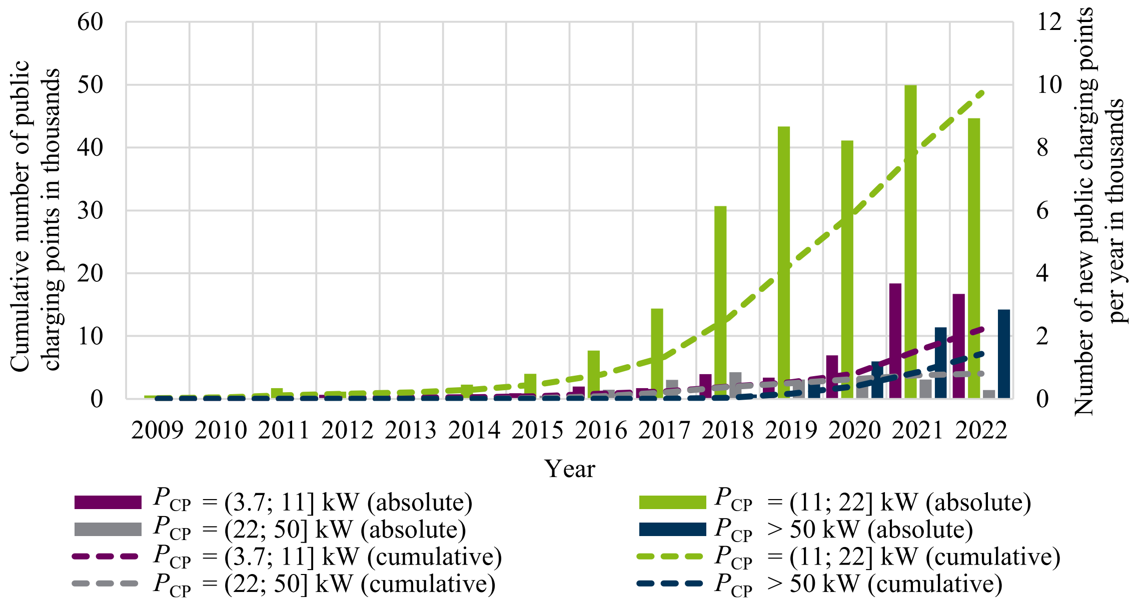

Figure 2.1: Development of the charging power and the number of public charging points in Germany published in [44] based on [40]

[2] A square bracket, [or], is used to indicate a closed interval. Parentheses, (or), are used to indicate an open interval, e.g. a < x ≤ b is equivalent to (a, b].

Generally, different charging powers are installed according to the data published by FGA [44]. Nevertheless, the most common charging powers P_{CP} = 3.7 kW, P_{CP} = 11 kW, P_{CP} = 22 kW, P_{CP} = 50 kW and P_{CP} = 150 kW with an assumed $\cos(\varphi) = 1$ are considered for further analyses. The selection of a few specific rated charging powers facilitates the modelling of the CP loads and the interpretation of the results later on. For a more differentiated investigation of the CPs, the charging powers are additionally divided into prCPs with P_{CP} = 3.7 kW, P_{CP} = 11 kW and P_{CP} = 22 kW, and puCPs with P_{CP} = 11 kW, P_{CP} = 22 kW, P_{CP} = 50 kW and P_{CP} = 150 kW. Building on the historical development of the charging power, a distribution of charging powers is assumed for prCPs and puCPs over the investigation years. The selection and distribution of the charging powers are discussed in the modelling of the EVs explained in section 3.4 (p. 28).

Hereby, it is determined that the puCPs provide higher charging powers throughout the analysis in comparison to the prCPs. This stems from the Technical Rules for the Connection of Customer Installations to the Low-Voltage Grid and their Operation (VDE-AR-N 4100) [45]. It states that "Charging devices for electric vehicles with rated powers $P_{CP} \geq 3.6$ kVA as well as all energy storage units must be registered at the grid operator" and that "the connection of charging devices for electric vehicles, if their total rated power exceeds 12 kVA per customer installation, requires the prior assessment and approval of the grid operator" [45]. Both statements have the consequence for later analyses that in the private sector P_{CP} = 3.7 kW and P_{CP} = 11 kW charging power only have to be registered, whereas the charging power P_{CP} = 22 kW has to be approved by the DSO. Therefore, it is more likely that the prCPs with P_{CP} = 22 kW are not going to be as widely installed in the grids as much as the prCPs with P_{CP} = 11 kW. In comparison, the parking times are much shorter at puCPs, which would require higher charging powers than for the prCPs.

Moving on, the economic framework conditions need to be investigated. These refer to the cost items that arise with the increasing expansion of CPs. Among the central cost factors for the acquisition and installation of a CP are (1) the charging power, (2) the number of charging ports, (3) the LM system and peripherals and (4) the type of mounting system [46]. In general, (1) the higher the charging power is, the more expensive the CP becomes. Similarly, increasing (2) the number of charging ports in a CP increases its price. Moreover, the addition of (3) LM system and peripherals increase its price as well. Independent of the CP's technical characteristics, (4) the type of mounting system greatly influences the CP's cost as the construction costs differ depending on whether the CP is wall mounted or pedestal mounted and whether in a confined space (e.g., garage) or in an open area (e.g., the road curb). With the focus on Germany, a rough estimate for the net costs associated with the installation of CPs is provided by [47]. The estimate differentiates the costs into subcategories including hardware installation, grid connection costs and authorisation/planning costs. Furthermore, it is assumed that the installation costs are decreasing in the future, which encourages the further spread of CPs. With the governmental plans to accelerate the spread of EVs, several countries offer their citizens a subsidy for purchasing EVs with conditions varying from one country to another [48].

Accordingly, the spread of CPs will accelerate. For connecting CPs of higher charging powers ($P_{CP} \geq 150$ kW), it must be examined whether the CP should be connected at the LV level or whether it is more appropriate to be connected at the MV level using a dedicated substation. Besides the hardware costs, which become more expensive with higher charging powers, a significant cost factor for the spread of CPs is the grid integration by the DSO, including the connection costs. Furthermore, it can be assumed that the prices for charging at puCPs with high charging powers will increase in the future, as it is a service and the costs for the corresponding puCPs must be covered. Depending on the development, prices may fall due to increased competition or due to economies of scale. Nevertheless, the installation costs of the CPs are not relevant to the DSO in the context of the grid planning as the installation costs of the CPs are paid by the corresponding CP owner and operator.

2.1.2 Development Scenarios for Electric Vehicles

Several studies have been published regarding development scenarios for EVs. Here, the focus is on the development of EVs in Germany. Therefore, a meta-analysis is performed of the relevant studies and their constructed scenarios. The meta-analysis considers the assumptions made by the respective studies for the construction of scenarios and the general framework conditions and impact factors taken into consideration. Finally, the development of EVs in the investigated studies in terms of the assumed total number of EVs in Germany is illustrated in Figure 2.2 (p. 11). It shows that the development scenarios can be grouped into two main groups: conservative (or pessimistic) and progressive (or optimistic). These two groups are differentiated by colour, where the conservative scenarios are shown in grey colour. The progressive scenarios are indicated by the light bluish colour. By analysing the development scenarios and their corresponding year of publication given in [49], it seems that the scenarios published between 2018 and 2020 assume a rather pessimistic spread of EVs in comparison to the studies published before 2018. This pessimistic assumption is quickly reversed in the past two years when governments around the world adopted a rather progressive action to further increase the integration of EVs, e.g., [50].

From each of the conservative and progressive groups, a middle scenario is chosen to be investigated. The goal is to consider both development trends without choosing an extreme scenario that is less likely to occur. Hence, the scenarios Q and R from [51] are adopted and are referred to as the conservative and progressive scenarios, respectively. The large number of different scenarios in Figure 2.2 (p. 11) shows that there is a great deal of uncertainty in the development of EVs, especially in the long time horizon. Therefore, the scenarios can only be selected for further use in grid planning in an individually designed process for the respective DSO. The implementation of the development scenarios in the grid planning along with the framework conditions is described in section 3.4 (p. 28). Besides the EVs, there are other developments relevant to planning that influence the potential expansion requirement. This includes HPs and DG, which are discussed in the following sections.

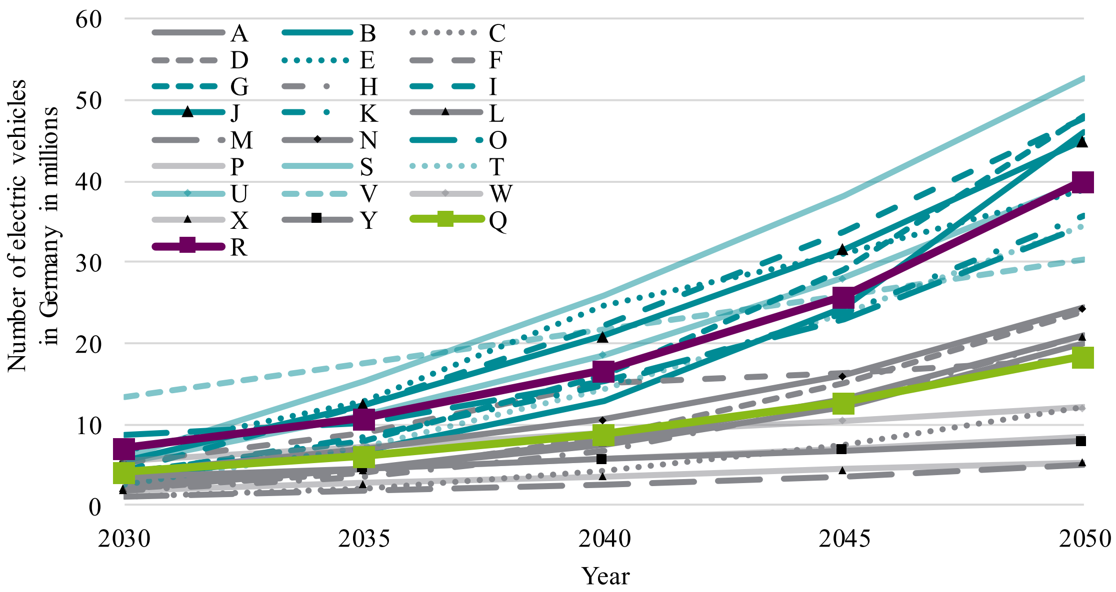

Figure 2.2: Development scenarios for electric vehicles in Germany up to the year 2050 based on [49]

2.2 Fundamentals of Heat Pumps[3]

HPs are one of the Power-to-Heat technologies, which deal with the conversion of electrical energy into thermal energy. The tasks performed by HPs can range from heating the living space to heating the household water usage and heating industrial process(es). The latter is mostly provided by large-scale HPs or large electric boilers. These can be individually integrated into the grid as they represent single-cases. Whereas HPs that are used in households either for heating living spaces or for heating household water usage are expected to be widely spread into the grids and are, therefore, the focus of the work.

Since the dimensioning and the resulting load of the HPs depend on the heating demand to be supplied for a specific household, the derivation of generally valid HP load profiles for all urban households is technically infeasible. Hence, the following section focuses on the general framework conditions for HPs independent of a certain HP type or dimension.

2.2.1 General Framework Conditions of Heat Pumps

Starting with the technical framework conditions, several factors must be considered for dimensioning the HP. Among these factors are (1) the power demand for heating the living space, (2) the power demand for heating the water usage, (3) possible turn-off periods[4] according to the DSO's regulations, (4) the selection of the heat source, (5) the operating mode and (6) the operating power. These factors must be known in advance for installing HPs. [53]

[3] The findings in this section have already been published in [40].

[4] Turn-off periods are periods during which an electrical installation is temporarily and actively disconnected (switched off/blocked) from the distribution grid by the grid operator and is not (fully) available to the consumer during this time [52].

Starting with (1), the power demand for heating the living space of residential buildings must be calculated individually. Essentially, it depends on the type of building insulation and the occupancy of the building. Calculating the specific heating load for the living space is presented in EN 12831-1 [54]. In addition to the power demand for heating the living space, (2) the power demand for supplying the hot water usage must be determined. With an increasing number of people in the household, hot water usage increases. Hence, the hot water usage (indirectly the number of people in the household) directly influences the dimensioning of the HP.

Likewise, it must generally be taken into account whether any (3) turn-off periods are enforced by the DSO. This must then be included in the total heating power demand with a turn-off period factor. Turn-off periods of a maximum of two hours for three times per day are common [52]. The pause between two consecutive turn-off periods must be at least as long as the preceding turn-off period. To substitute for the turn-off periods, the HP needs to be dimensioned larger than the actual heat demand to recover the heat loss during the turn-off period.

Moreover, (4) the selected heat source (air, brine, water) is decisive for dimensioning the HP. According to the selected heat source, the coefficient of performance of the HP differs and, consequently, the required HP dimension [55].

Additionally, (5) the operating mode of the HP influences the required HP dimension. In a monovalent mode of operation, a HP must be dimensioned to provide the total heat demand at all times, including the coldest day(s) of the year. In contrast to the monovalent mode of operation, a bivalent mode of operation combines the HP with a supplementary direct electrical heating element. This can be designed so that the HP provides the heating demand up to a certain outdoor temperature (e.g., $T = -10$ C°). When the temperature drops below the specified temperature, the supplementary heating element kicks in to provide the remaining heat demand [53].

The aforementioned factors, along with (6) the operational power, must be determined for dimensioning the HP before installing it. In the context of grid planning, it is infeasible to determine these individual factors for all buildings in the grid area. Hence, the results of an already existing market research are used to determine common power values for HPs P_{HP} without a heating element. The market research differentiates the HPs in terms of the heat source and the operational power. The operational power describes whether the HP runs constantly with its rated power (fixed operational power) or with a fluctuating power (regulated operational power) according to the heat demand. According to [56], the following systems are analysed:

- Air source with fixed operational power (526 units)
- Air source with regulated operational power (1,083 units)
- Ground source with fixed operational power (899 units)
- Ground source with regulated operational power (336 units)
- Water source with fixed operational power (559 units)
- Water source with regulated operational power (150 units)

The rated power values of HPs are categorised into power ranges of $P_{HP} < 3$ kW, $P_{HP} = [3; 5]$ kW and $P_{HP} > 5$ kW. The share of each of the power value categories for each of the HP types is shown in Figure 2.3. For each HP type, a "fixed" and a "regulated" operational power are presented. The evidence shows that the share of HPs with $P_{HP} < 3$ kW is approximately 60 % for all HPs with a fixed operational power. For air source HPs, the share of HPs with $P_{HP} < 3$ kW increases by utilising regulated HPs instead of fixed operational power. In contrast, the share of HPs with $P_{HP} < 3$ kW decreases for the ground source and the water source HPs by employing regulated operational power HPs.

The HPs with $P_{HP} < 3$ kW and $P_{HP} = [3; 5]$ kW represent around three-quarters of the market for all HP types apart from the water source HP with regulated operational power. Even though the HPs with $P_{HP} > 5$ kW represent more than half of the water source regulated operational power HPs, their absolute number remains significantly limited as they have the least number of units in the analysed database. By considering the number of units of each of the HP types along with the share of the power value categories shown in Figure 2.3, it can be concluded that the majority of the HPs currently available on the market have a nominal power of $P_{HP} < 3$ kW. This conclusion is utilised in the power value assumptions for HPs presented in section 3.5.2 (p. 39).

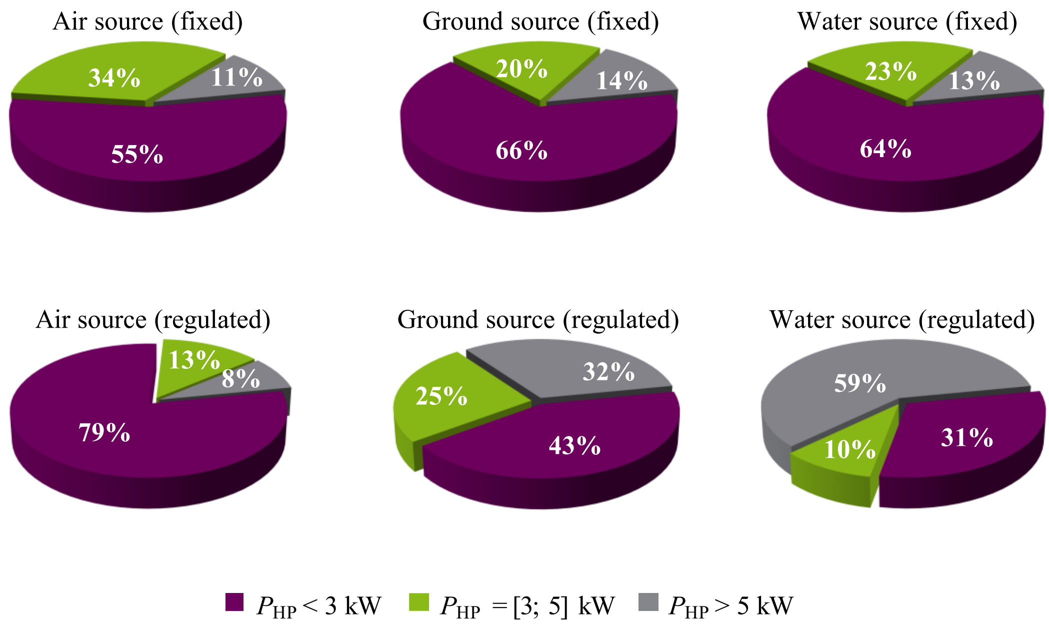

Figure 2.3: Share of the power value categories for different heat pump types based on [40]

In addition to the above-explained technical framework conditions of HPs, the economic framework conditions of HPs need to be analysed. According to the HP type, the capital-related costs differ. For instance, the costs for drilling into the ground or the laying of a ground collector in the case of a ground source HP are not considered for air source HPs. The constructional restrictions for water source HPs are costly in comparison to ground source and air source HPs.

In terms of installation costs, it can be concluded that the air source HPs currently have the least installation costs in comparison to ground source HPs or water source HPs. The installation costs for ground source HPs are higher since, among other factors, deep drilling has to be carried out to tap the heat source in the ground, which is not necessary for air source HPs. [57], [58]

The different factors for the capital-related costs sum up to the total purchasing cost of a HP. In numerous cases, the HPs are more expensive than conventional heating systems such as gas boilers. It must be considered that the total purchasing costs vary greatly depending on the manufacturer, the rated heat output and the efficiency. The higher the performance and the seasonal coefficients of performance of HPs, the more efficiently the electricity required for operation can be used.

Besides the total purchasing costs, the usual operating costs for running and maintenance must also be included, as well as any additional costs for supplementary heating or storage systems. Both the purchasing cost and the operating costs are irrelevant to the DSO, as these costs are paid by the HP owner and are not relevant to the grid planning costs.

In summary, it can be stated from the economic framework conditions that HPs are for the mass market still more expensive than conventional heating systems in terms of installation and current operating costs. However, the advantages of heat pumps outweigh the total costs over their useful lifetime, if they are designed correctly. Therefore, they are considered a viable technology for the future energy transition.

2.2.2 Development Scenarios for Heat Pumps

Similar to the analysis performed for EVs, a literature survey of the development of HPs is executed. Figure 2.4 (p. 15) shows the analysed scenarios for the development of HPs in Germany in the period from 2030 to 2050 based on the market analysis done in [59].

Starting with the scenarios "Agora-95", "dena-EL95", "BDI-95" and "BDI-80", these scenarios deduce the development of the HPs based on the needed development to achieve the global climate protection goals. In this case, the current market situation and development trends of HPs are not considered. Whereas the scenarios "Sc.1" and "Sc.2" developed by BWP[5] rely on different general framework conditions. The scenario "Sc.2" is based on current measures to improve HP sales, ranging from government subsidies on HPs to an optimised legal framework to increase the competitiveness of HPs. This scenario overlaps the scenarios "dena-TM80", "NEP-Sc.B" and "NEP-Sc.C"[6] and is adopted as a realistic progressive scenario for the development of HPs.

[5] These scenarios are developed by BWP or "Bundesverband Wärmepumpe" which translates to "Federal Heat Pump Association". BWP is a German association of around 500 members representing different stakeholders that are key players in the development and integration of heat pumps.

[6] These scenarios are published in [60] and added to the scenarios investigated in [59].

Analog to the development scenarios of EVs, a second conservative scenario for the development of HPs is adopted, namely, the scenario “Sc.1”. Based on an analysis of the current HP sales statistics, the scenario “Sc.1” is an extrapolation of the current market development of HPs. It can be argued that the two chosen scenarios are pessimistic concerning the development of HPs as both of them are found in the intermediate and bottom of the shown chart. To fully retrace the decision for choosing the scenarios “Sc.1” and “Sc.2”, two aspects should be mentioned. Firstly, this work focuses on the integration of HPs into urban areas. It is well known that urban areas are characterised by dense building structures with limited space for installing a HP. Moreover, the heat demand of the multi-storey buildings existing in the urban areas corresponds to high dimensional HPs, which in turn requires a bigger area for installation. Hence, a moderate to a sparse penetration of the HPs can be foreseen in urban areas. Secondly, the shown scenarios regarding achieving the global climate protection goals are regarded as rather theoretical development scenarios. Aside from these goals, the factors driving the spread of HPs into the grids are the HP sales and the governmental measures for adopting HPs in terms of subsidiaries and a regulatory framework. Moreover, the German government has recently published scenarios in [50] depicting a strong integration of HPs into the households. These are regarded as optimistic political goals, which are hard to be achieved practically. Hence, the scenarios that consider these factors, namely, “Sc.1” and “Sc.2”, are determined to be the most likely development scenarios for HPs. The development of HPs depends on the area space heating, which can be very diverse. Therefore, three HP models (see section 3.5.2, p. 39) are investigated in addition to the two chosen scenarios.

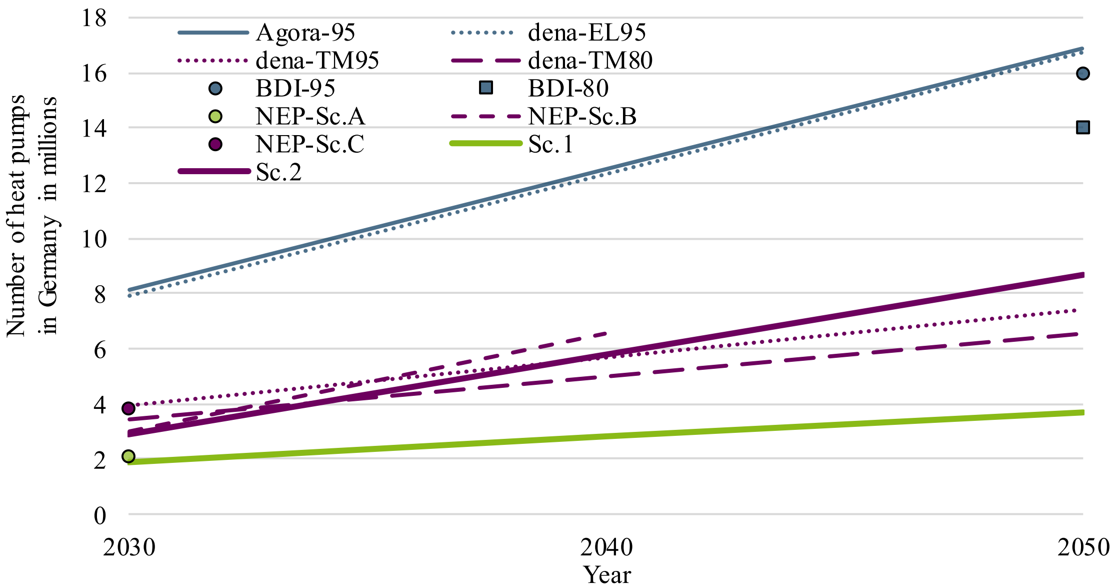

Figure 2.4: Development scenarios for heat pumps in Germany up to the year 2050 based on [59]

This concludes the analysis of the load-acting elements of the energy transition represented by the EVs and HPs. Moving on to the generation side of these elements, the following section continues with the DG, specifically the fundamentals of PV systems.

2.3 Fundamentals of Photovoltaic Systems[7]

In addition to PV technology, concentrated solar technology can be used to generate renewable electricity from the sun. As opposed to PV technology, concentrated solar technology converts solar energy to thermal energy for electricity generation [61]. Several comparisons (e.g., [62], [63]) between these two technologies in terms of efficiency and environmental impact have been performed. Due to the space restrictions of the concentrated solar plants, they can neither be implemented in urban areas nor connected to the urban grids. Therefore, the focus is on the integration of PV technology into urban grids.

In contrast to the presented new loads for which nearly no experience or historical data are available, the PV systems have already been existing in the grids for several years and have been widely investigated. Hence, the general framework conditions are briefly summarised in the following section.

2.3.1 General Framework Conditions of Photovoltaic Systems

Generally, the market penetration of PV is subject to two influencing factors. On the one hand, the installed power of the PV system $P_{\text{inst.}}$ correlates strongly with the area of the PV system at the respective location. Household owners aim to maximise the area of the installed PV system to maximise their peak power generation. Hence, the household owner can save more money on their electricity bill. This, however, depends on the ever-changing retail price of electricity. On the other hand, the construction costs increase with the installed power. Hence, from an economic point of view, the two factors, namely, the area of the installed PV system and the available budget for it, have to be simultaneously considered before installing the PV system(s). [64]

In contrast to centralised power plants, the operators of PV systems are owned not only by public or commercial companies but also by a majority of private owners representing different interests. Public and commercial companies aim to maximise their PV generation as much as possible to maximise their revenues from the fed-in power into the grid. Whereas the private owners of PV systems (e.g., on building rooftops) focus on increasing the degree of self-sufficiency to reduce their energy consumption from the grid [65]. In this case, a combination of the PV system with a battery storage system can become beneficial [66]. These battery storage systems can reduce the impact of PV systems on the grid. Nevertheless, the DSOs cannot depend on them in the grid planning as they are controlled by the PV system owner and do not follow a grid-oriented operation.

Besides the technical framework conditions for the development of PV, the economic aspect plays an important role in the development. Government incentives, in addition to feed-in tariffs and tax cuts can encourage the private owner to acquire and install PV systems [67].

[7] The findings in this section have already been published in [40].

Furthermore, several regulatory conditions control the feed-in power from PV systems. According to the installed power of a PV system, the DSO can enforce feed-in management on the PV systems. Hereby, the DSO maintains the capability to limit the feed-in power from a PV system according to the current grid state. In some cases, a long-term feed-in power limitation of a PV park may be enforced until the DSO performs the necessary grid reinforcement measures.

2.3.2 Development Scenarios for Photovoltaic Systems

The development scenarios for PV do not indicate an absolute number of PV systems, but rather a forecast for the installed capacities that result from the sum of the theoretical PV potential in a certain country. The PV potential is estimated according to the specifications of the nameplate of PV modules. These nameplate specifications are experimentally deduced under laboratory conditions. It must be taken into account that these nameplate specifications are not achieved under real conditions due to several factors, such as solar angle, shading and dust [68]. Although the operating behaviour of PV systems can be predicted, it can only be controlled to a limited extent, as the generated power is strongly dependent on the respective weather condition. In the context of forecasted PV power generation, the varying irradiance of sunlight and the number of given sunshine hours are to be considered. Based on the technical and economic framework conditions summarised above, Figure 2.5 shows an overview of the researched development scenarios over the upcoming years up to 2050. Similar to the development scenarios of EVs and HPs, the PV development scenarios are also split into two corridors; a progressive and a conservative corridor. To cover a wide spectrum of PV development, a mean scenario from each of the corridors is chosen, which are the scenarios “UBA-GreenLate” and “dena-TM-80” as a progressive and a conservative scenario, respectively.

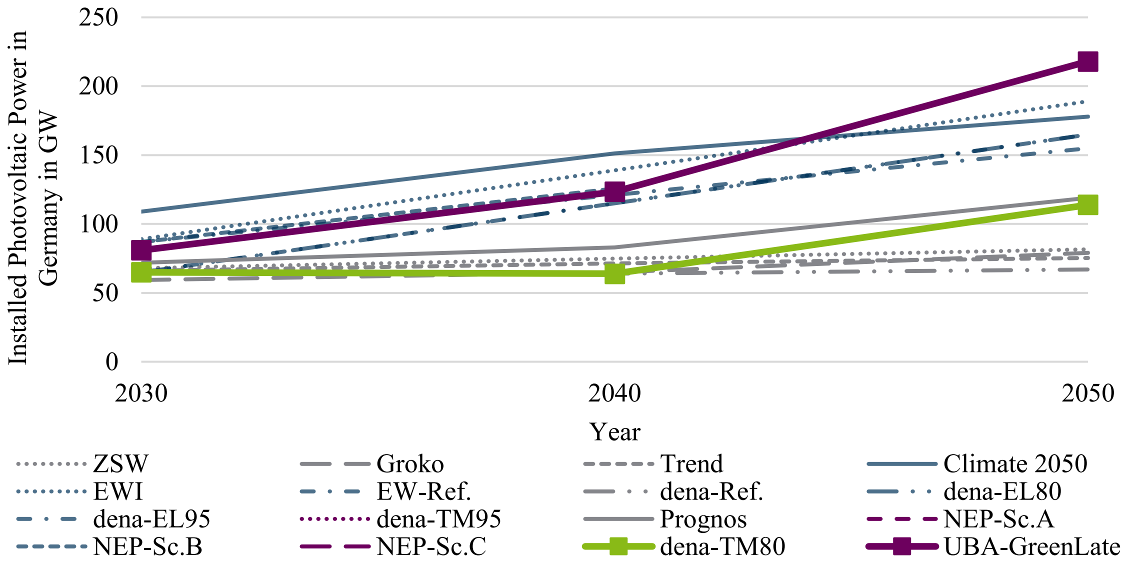

Figure 2.5: Development scenarios for photovoltaic power in Germany up to 2050 based on [40]

The aforementioned elements are not the only drivers for the energy transition. Several other elements have been developed in the recent few years.

2.4 Further Elements of the Energy Transition

In addition to the technologies explained in the previous sections, there are further elements contributing directly to the energy transition.

Beginning with the conventional household loads, they are expected to contribute to the energy transition. As they are not considered as a dedicated technology to accelerate the energy transition, their development is explained in section 3.3 (p. 25). Similarly, the contribution of the industrial and the commercial loads to the energy transition and their future development is described in section 3.3 (p. 25) as well.

Moving on to the mobility sector, the electrification of the public transportation sector can lead to a successful leap towards emission-free roads. Even though a part of public transportation is already electrified (such as the subway or the tram), the majority of the buses on the street are running on combustion fuels. The electrification of the bus fleets requires the development of a suitable charging infrastructure. According to the driving profiles of the bus routes, the expected number of passengers, their parking periods, and parking places, a suitable charging strategy can be adopted. Even though the electrification of the bus fleets occurs mainly in the urban area, it is not considered for two main reasons. Firstly, the above-mentioned factors for implementing a charging strategy differ from one city to another depending on the topography of the city and its demands. Hence, a general charging strategy for bus fleets cannot be deduced for all urban areas. Secondly, the available charging options for busses (e.g., depot charging) exhibit high charging powers that require a direct connection to the primary substation or even to the upstream HV grid.

A further technology for the energy transition is the Power-to-Gas station. The term Power-to-Gas station refers to the Power-to-Hydrogen technology as well as the Power-to-Methane technology. Generally, Power-to-Gas stations rely on a chemical process of water electrolysis (in the case of Power-to-Hydrogen) or synthesising methane (Power-to-Methane) to generate an emission-free fuel [69]. Ideally, the power consumed by the Power-to-Gas station is generated through renewable energy sources to ensure a low-emission process. Unlike the countrywide spread of CPs, HPs and PV systems, the Power-to-Gas stations are installed individually with a case-by-case analysis. In this case, they are most likely to be connected to the grid using a dedicated grid connection. By considering these constraints, it can be safely deduced that Power-to-Gas stations currently represent specific individual planning cases and are, therefore, not considered to be widely integrated into the grids. Likewise, large-scale HPs for industrial operations and district heating are not considered.

One technology that has been developed in the recent years and has shown potential is the ES. Its size and application can vary from optimally utilising the electric power generated using the DG in a household to remedying bottlenecks in the grid.

The ES systems installed in households in combination with a PV system are already discussed in section 2.3.1. As for the ES systems that remedy bottlenecks in the grid, these are investigated as an innovative technology in section 3.9.3 (p. 58).

As for the renewable energy generation, wind turbines are increasingly having higher peak power and are being installed onshore as well as in offshore locations. Several factors are to be considered for constructing a wind farm, such as the site selection, the number, and the type of wind turbines and the laws and regulations at the site [70]. Similar to PV, the energy generation from wind farms depends significantly on the current weather conditions at the specific location. Offshore wind farms are obviously not connected to the urban distribution grids and are, therefore, not considered in this work. Moreover, due to the spatial constraints for installing onshore wind farms, the wind farms cannot be located within urban areas. Hence, the offshore as well as the onshore wind farms are not considered, even though the impact of the expansion of wind farms on the transmission and rural distribution grids needs to be analysed.

Continuing with the energy generation, the micro combined heat and power system–referred to as a micro-CHP system–are regarded as a viable solution for both electricity and heat generation. The generated electricity and heat are then used to suffice the electric and heat demand of residential and small commercial buildings. The micro-CHP systems can reduce the primary energy consumption and, in turn, reduce carbon emissions [71]. Nevertheless, these systems still have high construction costs and are technically complex in operation. Moreover, they represent individual use cases, which are unexpected to be widely integrated into the grids. Hence, micro-CHP systems are not analysed any further.

3 Methodology of the Strategic Grid Planning

After identifying the elements of the energy transition in the electric grids, grid planning is necessary to ensure the capability of the grid to withstand the impact resulting from the new elements of the energy transition. The performed grid planning can be short-term or long-term planning. On the one hand, short-term planning focuses on the timeframe starting from the time of the planning up to three years in the future. Installing new equipment or predicting the system behaviour are possible studies that can be done in short-term planning. On the other hand, long-term planning focuses on the timeframe starting from three years in the future and longer generally ten to 20 years. The long-term planning addresses the grid reinforcement and expansion measures. These timeframes can change according to the DSO's internal regulations. [6]

As the integration of the elements of the energy transition spans a timeframe much longer than three years (see sections 2.1.2, 2.2.2 and 2.3.2), long-term planning of the MV grids becomes necessary. This long-term planning is referred to as strategic grid planning.

This chapter is arranged in the same order for executing strategic grid planning. Firstly, it starts with defining the MV grids as a basis. Secondly, the method for determining the MV grid state is described. The chapter continues by introducing the modelling of the new elements in the MV grids. The modelling compromises the identification of the number and location of the new elements, as well as their corresponding power values. With the new elements modelled in the grids, the chapter continues with identifying the permissible grid limits that need to be maintained. For the case of a grid limit violation, the chapter proceeds with grid planning measures categorised into conventional planning measures and innovative planning technologies. Finally, the chapter explains how the resulting planning alternatives can be assessed.

3.1 Concept of the Medium-Voltage Grids

MV grids serve as coupling grids between the LV and the HV level. Hence, they have similar characteristics to both voltage levels. Similar to the LV grids, the MV grids supply end customers, which are in most cases industrial customers referred to later on as "customer substations". Simultaneously, MV grids are similar to the HV grids, as both of them supply several downstream grids, for which they are accountable for their voltage stability.

According to [72], the nominal voltage V_n of MV grids is generally between 1 kV < V_n < 60 kV. The MV grids in Germany usually have a nominal voltage V_n of 10 kV < V_n < 30 kV. Since the analysed MV grids operate at the voltage levels V_n = 10 kV and V_n = 20 kV (see section 4.1.1, p. 67), these voltage levels are the focus of the work. Nevertheless, MV grids with V_n = 30 kV can be found in rural distribution grids in Germany.

MV grids consist of the same components, namely, a connection to the upper stream HV grid through a primary substation with HV/MV transformer(s). Out of which, several feeders[8] stretch to supply either the MV level end consumers through customer substations or to the downstream LV grids through secondary substations with MV/LV transformers. The voltage regulation is performed by the HV/MV transformer for the complete MV grid. The aforementioned components of the MV grid can be found in every MV distribution grid independent of the grid topology.

The MV grids follow several grid topologies. Among these topologies are the radial grid topology, the meshed ring topology and the radial ring topology. As the name suggests, the radial grid topology consists of single feeders branching out from the primary substation to the secondary and customer substations in a series connection. On one hand, this topology compromises the simplest grid topology in terms of design and operation and has a clear structure. On the other hand, they are not sufficiently reliable for the MV level, as a failure of only one line may lead to a long-lasting interruption of the power supply. [74]

Another possible MV grid topology is a meshed ring topology. The ring main system consists of line rings that start at the primary substation, extend to the secondary and customer substations and end back at the primary substation. Additionally, lines between the secondary and customer substations can be extended, thus creating a mesh that ensures supply through multiple paths. In a meshed ring topology, all secondary and customer substations can still be supplied if any single line fails. Even though the meshed ring topology improves the supply reliability and the voltage profile significantly, this topology is complicated to design and operate. Furthermore, the meshed topology contributes to higher short-circuit currents, which complicates grid protection. [74]

A widely spread MV grid topology is the radial ring. This grid topology consists of line rings that start at the primary substation, extend to several secondary and customer substations, and end at the primary substation. Switches along the ring lines are used to open the ring into two radial lines. With remote automated opening and closing of the switches, a ring line can be split into two radial lines with different line segments. This facilitates the resupply of loads in case of failure, as well as the short-term reduction of line loading in case of a load increase. The radial ring topology (typically referred to as "an open ring topology") combines the advantages of radial grids as well as ring grids. It has a relatively simple grid operation and protection. In addition, it maintains a stable voltage profile and ensures quick re-supply of the load in case of a failure. [74]

Due to the advantages of the radial ring topology, it is widely applied in urban MV grids. In the context of grid planning, identifying the grid topology accounts for the first step, after general planning assumptions need to be determined.

[8] "An electric line originating at a main substation and supplying one or more secondary substations" [73]

3.2 General Planning Assumptions

A MV grid can have several feeders stretching from a single primary substation to supply several secondary and customer substations. In the context of this work, modelling the MV grids starts from the HV busbar where the HV/MV transformer in the primary substation is connected and ends at the MV busbar, whether it is at a secondary or a customer substation. The MV/LV transformers, including the switching gear in the secondary and customer substations, are excluded from the MV grid analysis.

Since a single primary substation supplies several loads in the grid area, the simultaneity of the peak load differs from a substation view to a feeder view. For grid planning, it is essential to correctly dimension the grid components according to the connected load. An over dimensioning can result in extra unnecessary investments and an under dimensioning may result in a violation of the grid limits. For dimensioning the grid components using a load flow analysis, two approaches can be implemented. The first approach relies on a time series analysis where a time series is generated for each load DG element and ES in the grid. By performing a time series analysis, the time difference between the peak load and generation is considered and a load flow can be calculated. The accuracy of the calculated load flow depends on the preciseness of the times series of the individual load and DG elements. In this case, the load flow analysis requires a relatively long computational time and load time series to perform the load flow calculations [75].

The second approach relies on the implementation of Demand Factors (DFs) and operating points. The DF is defined as: "the ratio, expressed as a numerical value or as a percentage, of the maximum demand of an installation or a group of installations within a specified period, to the corresponding total installed load of the installation(s)" [76]. Since the application of DFs depends on the simultaneity of a group of installations, the DF considers two main parameters for the load flow analysis. The first parameter is the specific type of the installations, whether it is a specific load or DG type. The second parameter is the number of units in the group of installations. Depending on these two parameters, the DF can be determined for a certain group of installations connected to a specific grid component. Consequently, the determined DF can be input into the load flow analysis to calculate the load flow through the grid component and to dimension it.

In comparison with a time series analysis, [77] has proven that the implementation of DFs results in the correct dimensioning of the grid components. Hence, DFs for the load and DG modelling in addition to two planning perspectives (i.e. the transformer planning perspective and the feeder planning perspective) are considered.

The two planning perspectives: the transformer planning perspective and the feeder planning perspective are for the dimensioning of the primary substation transformer and the feeders, respectively. These two planning perspectives differ mainly in the number of considered loads and their corresponding demand factor (DF) value.

In the boundaries of the MV grid planning, the two investigated planning perspectives are the primary substation HV/MV transformer planning perspective and the MV feeder planning perspective. For readability reasons, the terms “transformer planning perspective” and “feeder planning perspective” are used instead.

In addition to the planning perspectives, grid operating points are adopted in modelling the loads and the DG. An operating point is defined as a “point on a characteristic curve representing the values of variable quantities at which a system is operating” [78]. For the strategic grid planning, two operating points are usually adopted, namely, the “peak load” operating point and the “peak generation” operating point. The operating points are deduced according to the load and generation situation in the grid.

In the peak load operating point, it is assumed that the load draws 100 % of its power and that the DG systems do not feed in any power into the grid. This assumption ensures that, in case the DG systems do not generate power, the grid can supply all the loads in the grid without exhibiting any grid limit violations. In contrast, the peak generation operating point assumes that the DG systems feed in power into the grid and that the load draws 30 % of their power. The simultaneous consideration of these two operating points investigates the grid state in two opposing, yet probable, operating points. In the load flow analysis, the modelled load power P'_{load} in relation to the load power P_{load} and the modelled DG power P'_{DG} in relation to the DG power P_{DG} are adjusted according to the operating point. For the peak load operating point, equation (3.1) and equation (3.2) are applied.

$$P'_{\mathrm{load}} = 100\% \cdot P_{\mathrm{load}} \tag{3.1}$$

$$P'_{\mathrm{DG}} = 0\% \cdot P_{\mathrm{DG}} \tag{3.2}$$

As for the peak generation operating point, equation (3.3) and equation (3.4) are applied for modelling the load power and the PV power, respectively.

$$P'_{\mathrm{load}} = 30\% \cdot P_{\mathrm{load}} \tag{3.3}$$

$$P'_{\mathrm{DG}} = 100\% \cdot P_{\mathrm{DG}} \tag{3.4}$$

The compound investigation of the two planning perspectives with the two operating points ensures the correct identification of the grid state in the grid planning. Hence, it is adopted for the performed grid planning. The assumed power factor ($\cos(\varphi)$) values for the different load and generation types are explained in the following sections, as they discuss the modelling of the different load and DG types considered. The modelling addresses the load power values, the power factor values, their distribution into the grids as well as the corresponding DFs.

3.3 Modelling of the Conventional Loads

The term "conventional loads" refers to household, commercial, and industrial loads. As for the household and commercial loads, they are not connected directly to the MV grid but rather are connected in the LV grids and over a secondary substation to the MV grid. As for the commercial loads, they refer to the electric loads of small businesses such as a kiosk or a hairdresser, which are connected to the LV grids too. Hence, the household and commercial loads are not individually modelled in the MV grids but rather as an aggregated load power P_{load}. Each aggregated load represents the complete downstream LV grid and is modelled at the corresponding grid node. The power losses in the downstream LV grids, along with the power losses over the secondary substation MV/LV transformers, are included in the aggregated load power. Accordingly, the secondary substation MV/LV transformer and the LV lines are not modelled separately. The industrial loads (e.g., shopping malls) refer to the loads supplied by customer substations directly connected to the MV grid and are modelled as MV loads connected directly to the MV grid at the customer substation node(s).

Since the conventional loads are not considered elements of the energy transition, a detailed analysis of the development of the conventional loads is not given in Chapter 2. Nevertheless, their development is analysed herein.

The development of conventional loads is influenced by the current trends in urban area development. Not only trends in the energy supply and consumption but also trends in urban and population development can influence the development of conventional loads, either directly or indirectly. Among the trends that influence conventional load development are urbanisation, the development of new space and settlement structures, energy efficiency, distributed energy conversion, population development, digitalisation, and automation.

These trends provide qualitative evidence of the urban area development rather than a quantitative measurable scenario. Therefore, in order to quantify the trends in terms of conventional load development, these trends need to be transformed into load-influencing factors and interdependencies need to be modelled where possible. [40]

Consequently, the investigated trends are transformed into impact factors of quantitative measurable parameters for the specific urban area. The transformed impact factors include the population of the city, commercial consumers, housing and building structures, the distribution of income structure, energy efficiency, and the electrification of the heating sector. Even though these impact factors are determined to influence conventional load development, a direct one-to-one effect cannot be assumed. Therefore, a load demand model has been developed to study the correlation of these impact factors to one another and their final impact on the conventional load development. [40]

The load demand model applies two-phase modelling; statistical modelling and deterministic modelling. The statistical modelling is applied for the dataset for which (1) historical data is available, (2) the impact on the load development is traceable and (3) a future projection is possible. Whereas, the deterministic model is used for the dataset for which no estimation of their influence on the load development can be made. [79]

The statistical modelling determines the relation between the independent historical variables (e.g., population development) and the dependent variables (e.g., peak load and annual energy consumption). The resulting model coefficients keep readjusted to minimise the deviation between the existing measured load values and the calculated load values. Once the model coefficients are determined, the scenarios for the abovementioned impact factors are fed into the model to determine the maximum annual consumption. The following deterministic model utilises the forecasted maximum annual consumption to scale the conventional load profiles. Finally, P_{load} is determined as the maximum load power in the generated load profiles for a given scenario. [79]

The above-explained model can be implemented for household loads since they exhibit a homogenous load profile. As for the commercial and industrial loads, their heterogeneity requires further detailed data, such as the type of the business and the opening hours. With the lack of this detailed information for all investigated MV grids, commercial and industrial loads are assumed to remain constant over the investigation years. Hence, the conventional load development is then determined as a combination of household loads along with commercial represented by the secondary substations and the industrial loads represented by the customer substations.

After determining the load development of the conventional loads, the load power values need to be modelled for performing the load flow analysis. Commonly, the load power values P_{load} of the conventional loads are not available for all MV grids. Instead, the current stay-set pointer value per secondary substation MV/LV transformer $I_{\mathrm{secondary}}$, the load power per customer substation P_{customer}, and the peak feeder current I_{F} pro MV feeder are usually widely available.

The $I_{\mathrm{secondary}}$ indicates the maximum current flowing through the secondary substation MV/LV transformer over a defined period. Generally, this indicates the individual peak load current of the corresponding secondary substation MV/LV transformer in a specific period. Similarly, the load per customer substation P_{customer} stands for the peak load of the corresponding customer substation in a specific period. Likewise, the peak feeder current I_{F} equals the peak current drawn in the feeder to supply all connected secondary and customer substations. Naturally, these individual values represent the individual maximum loads of each of the three measurement points (secondary substations in a feeder, customer substations in a feeder and the peak feeder current) and do not consider the simultaneity between the secondary and the customer substation loads in adding up to the peak feeder current. Hence, a scaling factor needs to be introduced to scale the $I_{\mathrm{secondary}}$ and the P_{customer} to meet the I_{F} per MV feeder.

Consequently, the scaling factor per feeder SF_F is calculated following equation (3.5). SF_F is a relation between the individual $I_{secondary}$ values along with the load values of the customer substations $P_{customer}$ in relation to the MV feeder measurement I_F. The scaling factor is then used to scale the load values of the secondary substations and the customer substations to meet the peak feeder current from the feeder planning perspective. The power factor value of conventional loads is set according to equation (3.6).

$$SF_F = \frac{I_F}{\sum I_{secondary} + \frac{\sum P_{customer}}{\sqrt{3} \cdot V_n \cdot \cos(\varphi)}} \tag{3.5}$$

$$\cos(\varphi) = 0.98 \tag{3.6}$$

Applying the calculated scaling factor SF_F to $I_{secondary}$ and $P_{customer}$ results in the correct power values from the feeder planning perspective. Subsequently, the load power values for secondary and customer substations need to be calculated from the transformer planning perspective. Hence, the general equation for calculating the DFs for different load types is applied according to [80].

Generally, the DF of a certain load type is calculated according to equation (3.7), where x_{DF} is a constant dependent on the load type and n is the number of units for the specific load type. In the case of household loads, the constant is set to be $x_{DF} = 0.07$ [80]. The number of loads n corresponds to the number of households per planning perspective, whether the equation is applied for calculating the DF from the feeder or the transformer planning perspective.

$$\mathrm{DF} = x_{DF} + \frac{1 - x_{DF}}{(n)^{0.75}} \tag{3.7}$$

In the case of MV grids, not only households are supplied but also commercial and industrial loads. Therefore, applying equation (3.7) per MV grid for the several feeders and the transformer can be a time-consuming calculation. Hence, a generally valid ratio between the load values from the transformer planning perspective to the feeder planning perspective is practical.

By applying equation (3.7) to several MV grids for both planning perspectives and by relating the power values from both planning perspectives, it was determined that the ratio in the DFs between the two planning perspectives remains in a certain tolerance over all MV feeders in all the investigated MV grids. Consequently, a relative value of the power value from the transformer planning perspective $P_{load,T}$ to the feeder planning perspective $P_{load,F}$ is applied for modelling the conventional loads according to equation (3.8).

$$\frac{P_{load,F}}{P_{load,T}} = 0.81 \tag{3.8}$$

Moving on from the modelling of the conventional loads, the following sections discuss the modelling of the elements of the energy transition.

3.4 Modelling of the Electric Vehicle Load

The EV load is represented by the CPs connected to the grid and required to charge EVs. The two main parameters for modelling any electric load in the grid are the location and the power value. Unlike the previously described conventional loads, the CPs are still developing and spreading into the grids. Therefore, there is limited reliable historical data for the CP loads to determine either their location in the grid or their future power value. Hence, the modelling of the CP load is associated with uncertainties related to their development scenarios and their nominal power values. The following two sections propose a mathematical method for modelling the CP load; starting with allocating the EVs in a specific MV grid area and continuing with specifying the corresponding load power value.

3.4.1 Scaling Down and Distribution of Electric Vehicles

After identifying the scenarios that are most likely going to occur, these scenarios need to be scaled down for the respective MV grid. The basic process for scaling down the scenarios is a top-down approach from the countrywide scenarios identified in section 2.1.2 to the grid-specific number of EVs. The scaling down process is shown in Figure 3.1. Firstly, the number of EVs is scaled from the country level to the state level. This number of EVs for the state level is scaled down to the city level. Then, the number of EVs on the city level is scaled down to the district level and finally to the street level. [49]

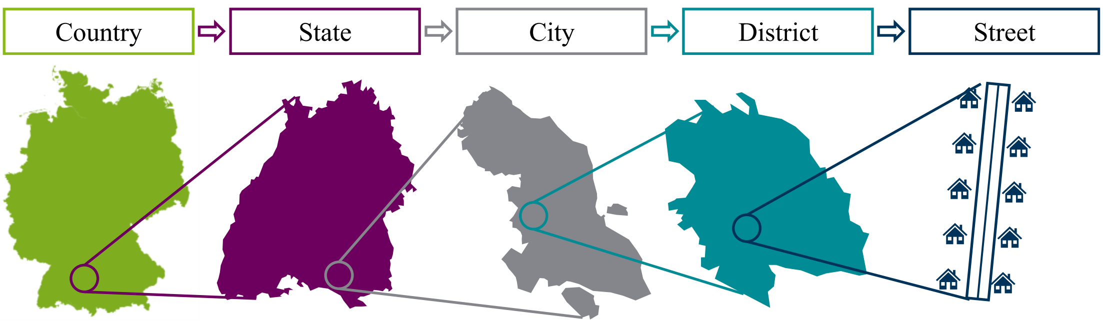

Figure 3.1: The scaling down process for electric vehicles based on [40]

First, the total number of EVs on the country level $EV_{\text{country},y}$ in the year y (y=2030, 2040 or 2050) can be determined by using the scenarios selected in section 2.1.2. The first scaling down step to the state level considers a set of distribution factors which differ in value from one state to another. In this step, the parameters considered as distribution factors on the state level are the current values of population (Pop), the recent number of EVs (NoEV), the number of car owners (NoCO), the funding projects for electromobility (FP), the number of buildings (NoB), and the total number of vehicles registered (NoV). Each of these parameters is transformed into a distribution factor on the state level $F_{\text{Pa,state}}$ by calculating the ratio of the absolute value of this parameter from the state level $V_{\text{Pa,state}}$ in relation to its absolute value on the country level $V_{\text{Pa,country}}$. Hence, the distribution factors are unitless. The method for determining a distribution factor is given in equation (3.9).

$$F_{\mathrm{Pa,state}} = \frac{V_{\mathrm{Pa,state}}}{V_{\mathrm{Pa,country}}} \tag{3.9}$$

After determining the distribution factors of the parameters according to equation (3.9), the total number of EVs on the state level $EV_{\mathrm{state,y}}$ is calculated according to equation (3.10). The applied distribution factors ($F_{\mathrm{Pop,state}}$, $F_{\mathrm{NoEV,state}}$, $F_{\mathrm{NoCO,state}}$, $F_{\mathrm{FP,state}}$, $F_{\mathrm{NoB,state}}$, and $F_{\mathrm{NoV,state}}$) are multiplied with a specific weighting term ($w_{\mathrm{Pop,y}}$, $w_{\mathrm{NoEV,y}}$, $w_{\mathrm{NoCO,y}}$, $w_{\mathrm{FP,y}}$, $w_{\mathrm{NoB,y}}$, and $w_{\mathrm{NoV,y}}$). These weighting terms $w_{\mathrm{i,y}}$ change over the investigation years according to the importance of the corresponding distribution factor, so that the sum of the weighting terms equals one (see equation (3.11)). [49]

$$\begin{aligned} &EV_{\mathrm{state,y}} \\ &= EV_{\mathrm{country,y}} \cdot \big(w_{\mathrm{Pop,y}} \cdot F_{\mathrm{Pop,state}} + w_{\mathrm{NoEV,y}} \cdot F_{\mathrm{NoEV,state}} + w_{\mathrm{NoCO,y}} \cdot F_{\mathrm{NoCO,state}} \\ &\qquad + w_{\mathrm{FP,y}} \cdot F_{\mathrm{FP,state}} + w_{\mathrm{NoB,y}} \cdot F_{\mathrm{NoB,state}} + w_{\mathrm{NoV,y}} \cdot F_{\mathrm{NoV,state}}\big) \end{aligned} \tag{3.10}$$

$$\text{with} \sum w_{\mathrm{i,y}} = 1 \tag{3.11}$$

The resulting number of EVs on the state level is then scaled down to the number of EVs on the city level $EV_{\mathrm{city,y}}$ by applying equation (3.12). In this step, further parameters are applied as distribution factors for the respective city; which are the population (Pop), the population density (PopD) and the total number of vehicles (NoV) registered in the city. Similar to the prior scaling down step, the distribution factor of a certain parameter on the city level $F_{\mathrm{Pa,city}}$ is determined as a ratio between the absolute value of the parameter on the city level $V_{\mathrm{Pa,city}}$ to its value on the state level $V_{\mathrm{Pa,state}}$. Therefore, the distribution factors on the city level are also unitless and are determined according to equation (3.12).

$$F_{\mathrm{Pa,city}} = \frac{V_{\mathrm{Pa,city}}}{V_{\mathrm{Pa,state}}} \tag{3.12}$$

Each of the distribution factors ($F_{\mathrm{Pop,city}}$, $F_{\mathrm{PopD,city}}$, and $F_{\mathrm{NoV,city}}$) is then multiplied with a weighting term ($w'_{\mathrm{Pop,y}}$, $w'_{\mathrm{PopD,y}}$, and $w'_{\mathrm{NoV,y}}$) according to equation (3.13) to determine the number of EVs on the city level. The sum of the applied weighting terms $w'_{\mathrm{i,y}}$ mounts up to one (see equation (3.14)). [49]

$$EV_{\mathrm{city,y}} = EV_{\mathrm{state,y}} \cdot (w'_{\mathrm{Pop,y}} \cdot F_{\mathrm{Pop,city}} + w'_{\mathrm{PopD,y}} \cdot F_{\mathrm{PopD,city}} + w'_{\mathrm{NoV,y}} \cdot F_{\mathrm{NoV,city}}) \tag{3.13}$$

$$\text{with} \sum w'_{\mathrm{i,y}} = 1 \tag{3.14}$$

The applied weighting terms in the two previous scaling down steps are given in the appendix (Table 8.4, p. 156). The calculated number of EVs on the city level can further be scaled down to the district level and the street level by applying similar equations with differentiated distribution factors. By summing up the number of EVs in the streets of a certain MV grid, the total number of EVs in this MV grid can be determined per scenario and investigation year.

The execution of the aforementioned scaling down process requires the availability of the data used for each of the distribution factors at each scaling down step. In some cases, these data may not be available for the investigated MV grid. Hence, to ensure the reproducibility of the presented results, a second approach is developed to determine the number of EVs per MV grid.

Since the EVs are eventually allocated to the downstream LV grids, the second approach of scaling down determines the number of EVs in the MV grid depending on the available grid parameters for the downstream LV grids. Since the penetration of the EVs in a certain grid strongly correlates to the buildings supplied by the grid, a correlation between the number of EVs and the number of building connections is deduced.

As a basis for the second approach, the above-explained scaling down process of the EVs is performed for several LV grid areas. By analysing the final number of EVs per LV grid, the correlation between the number of EVs and the number of building connections is established. Generally, the expected number of EVs increases proportionally to the number of building connections supplied by the grid independent of its voltage level. By performing this analysis for the two selected scenarios and the three investigation years 2030, 2040 and 2050, six trend lines correlating the number of expected EVs to the number of building connections are deduced for each of these development paths. [40]

These trend lines are then applied to the total number of building connections supplied by the MV grid to determine the expected number of EVs per scenario and investigation year. Afterwards, the total number of EVs per MV grid is then split into three categories, namely, private, commercial, and commuter EVs according to the method described in [49].

After the numbers of private, commercial, and commuter EVs are determined per MV grid, they are converted to a corresponding number of prCPs, puCPs and ultra-fast Charging Points (ufCPs) per MV grid according to Figure 3.2 (p. 31). The ufCPs represent EV charging hubs that are selectively distributed in the city and connected directly to the MV grid. Since commercial EVs are usually privately used, it is assumed that they can be charged at prCPs along with private EVs. Since the prCPs are generally installed at the buildings, they are proportionally scaled down to the secondary substations according to their corresponding number of building connections. In contrast to prCPs, the puCPs can be accessed by any EV. Therefore, the number of the puCPs per MV grid $n_{\text{puCP,grid}}$ results from the sum of the private ($n_{\text{privateEV,grid}}$), commercial ($n_{\text{commercialEV,grid}}$)and commuter ($n_{\text{commuterEV,grid}}$) EVs. Furthermore, a factor of conversion from EV to puCP is introduced, since a puCP can serve several EVs. According to [51], a single puCP can serve up to 13 EVs. Hence, this factor is adopted for converting the sum of EVs to a number of puCPs per MV grid. This is done according to equation (3.15).

$$n_{\text{puCP,grid}} = (n_{\text{privateEV,grid}} + n_{\text{commercialEV,grid}} + n_{\text{commuterEV,grid}})/13 \tag{3.15}$$

Unlike the prCPs, the puCPs are expected to have a charging power reaching P_{CP} = 150 kW. Due to the available capacity restrictions in the LV level, the puCPs are split into puCPs to be installed in the downstream LV grids (modelled at the secondary substation nodes) and to ufCPs to be connected directly in the MV grid (modelled in the MV grid). 50 % of the puCPs that have the nominal charging power P_{CP} = 150 kW are modelled as ufCPs. The assumed charging power distribution is given in Table 3.1 (p. 33). Apart from the ufCPs, the remaining puCPs are to be attributed to the secondary substations. It is assumed that the number of building connections can loosely represent the dimension of the downstream LV grids. Therefore, the remaining number of puCPs is scaled down to the secondary substations proportional to their corresponding number of building connections. Since ufCPs and puCPs are publicly accessible by EV, their load values are consolidated and demonstrated as load values for the puCPs in the analysis shown in Chapter 4 (p. 67) and Chapter 5 (p. 95).

Generally, it is assumed that the charging infrastructure at customer substations is mainly used by commuter EVs. A commuter EV in this context refers to an EV commuting into the MV grid from outside of the MV grid area, independent of whether it is commuting into the MV grid from within the same city or from a different city/rural region. With this understanding, an EV moving from one part of the city to a different part of the city would also be considered a commuter EV, if these two parts of the city are supplied by two different MV primary substations. Therefore, the number of commuter EVs is converted into the number of CPs at the customer substations. Furthermore, the charging power distribution for the prCPs is assumed for the CPs at the customer substations, since these CPs are privately owned by the corresponding owner of the customer substation. Using GoogleMaps [81] and OpenStreetMaps [82], the number of parking spots are determined per MV customer substation. The determined number of prCPs at MV customer substations is then scaled down on the respective customer substation proportional to the number of parking spots. [40]

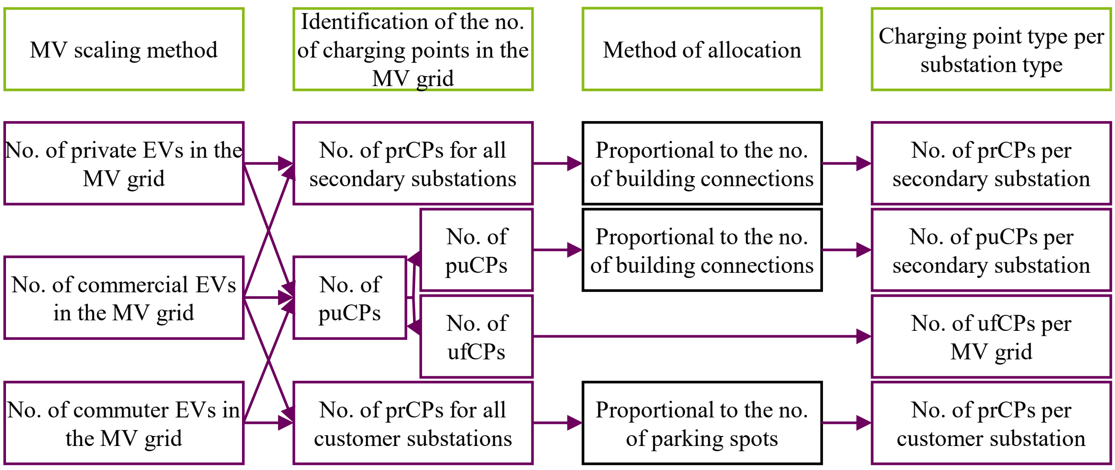

Figure 3.2: Transformation of the number of electric vehicles to charging points (MV = medium-voltage, EV = electric vehicle, prCP = private charging point, puCP = public charging points, ufCP = ultra-fast charging point, no. = number)

The transformation of the number of EVs to CPs results in CPs at different grid nodes, namely, prCPs at secondary substations, puCPs at secondary substations, ufCPs, and prCPs at customer substations. Afterwards, these CPs are modelled in the respective MV grid model as an additional load to the existing conventional loads at the respective grid nodes. The process of the apportioning model of the CPs in the MV grid is shown in Figure 3.3. The prCPs and the puCPs of the secondary substations are modelled at the corresponding grid node. Secondly, the $prCP_{CS}$ per customer substation is modelled at the corresponding grid node of the customer substation. Finally, the ufCPs are randomly distributed at the MV grid nodes. [83]

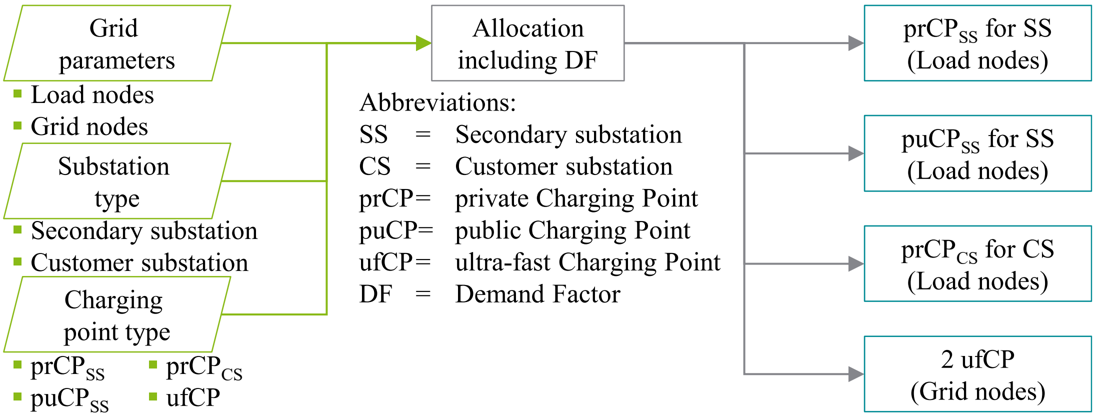

Figure 3.3: Apportioning of the charging points to the different load nodes in the medium voltage grids

With the number of CPs already determined per MV grid node, the modelled load power P_{load} is calculated according to the power assumptions and the DF calculation presented in the following section.

3.4.2 Power Assumptions and Demand Factor Calculation for Electric Vehicles

Based on the general framework conditions presented in section 2.1.1, the ratios of the charging powers for the prCPs and the puCPs are distributed according to Table 3.1 (p. 33). The ufCPs maintain a charging power of P_{CP} = 150 kW over the investigation years and are, therefore, not given in the table. The ratio of higher charging powers is assumed to increase from 2030 to 2040 similar to the development seen in Figure 2.1. This increase in the charging power is assumed to remain constant after the year 2040, as the technological development will most probably reach its peak by then. Furthermore, direct-current (DC) charging powers (P_{CP} ≥ 50 kW) are not foreseen for the prCPs as they would need individual building connections and special approvals (see section 2.1.1). The charging powers for the puCPs do not exceed P_{CP} = 150 kW. Even though there are currently CPs with higher charging powers (e.g., P_{CP} = 350 kW), it is assumed that the higher charging powers are not to be comprehensively installed in the MV grids. Due to the required power capacity, it is more likely that CPs with P_{CP} >150 kW are to be individually analysed in the grid planning. In this case, the corresponding DFs are given in the following section (see Figure 3.4, p. 35). Alternatively, CPs with high charging power can be analysed as charging hubs. An analysis of the charging hubs is presented in section 5.4.1 (p. 114).

Table 3.1: The assumed distribution of charging powers for the private and the public charging infrastructure per investigation year based on [79]

Investigation year	Charging power of private charging infrastructure			Charging power of public charging infrastructure			
	3.7 kW	11 kW	22 kW	11 kW	22 kW	50 kW	150 kW
2030	10 %	60 %	30 %	5 %	75 %	15 %	5 %
2040	0 %	65 %	35 %	5 %	20 %	50 %	25 %
2050	0 %	65 %	35 %	5 %	20 %	50 %	25 %

In addition to the assumed distribution of charging powers, the DFs for CPs are required for calculating the load power P_{load} of the prCPs and the puCPs. In [84], the DFs are deduced for prCPs by modelling the driving behaviours of sets of EVs. Among the modelled factors for the driving behaviour are the driving patterns (in terms of the time of arrival and the daily energy consumption), the probability of charging upon arrival and the utilization of the puCPs. The developed DFs are, however, limited to 100 EVs and to a maximum charging power of $P_{\mathrm{CP}} = 22$ kW. A similar study [85] determines the DF for prCPs based on statistical driving data. The presented DFs are also limited to 150 EVs and a maximum charging power of 22 kW. Even though these publications present DFs, which are sufficient for planning the private charging infrastructure in LV grids, the presented DFs are not sufficient for planning public and private charging infrastructure in MV grids.

Hence, for planning the private as well as the public charging infrastructure in the MV grids, DFs are developed for up to 500 CPs and for up to $P_{\mathrm{CP}} = 150$ kW. For any number of CPs that exceed 500 CPs, the DFs for 500 CPs are applied. In the context of grid planning, when the number of loads exceeds a certain threshold, a constant base load per unit of the load becomes realistically applicable. In the case of CPs, it is recommended to assume a constant DF effective from 500 CPs, which is also in line with [86].

The methodology for developing the DFs is similar to the methodology applied in [84], [85]. First, charging profiles are generated using a mobility tool developed in [87]. The tool uses the statistical driving data patterns published in [88] to stochastically generate daily driving profiles for EVs. These driving profiles are then utilised to generate charging profiles. [83]

By overlapping the generated charging profiles for a specific nominal charging power, the peak power demand P_{peak} for a certain number of CPs n_{CP} can be identified. Thereof, the DF for this specific number of CPs n_{CP} for the specific nominal charging power $DF_{\mathrm{n_{CP}},\mathrm{P_{CP}}}$ can be calculated using equation (3.16). [83]

$$DF_{\mathrm{n_{CP}},\mathrm{P_{Cp}}} = \frac{P_{\mathrm{peak}}}{n_{\mathrm{CP}} \cdot P_{\mathrm{CP}}} \tag{3.16}$$

The aforementioned steps are repeated for the nominal charging powers $P_{CP} = 3.7$ kW, $P_{CP} = 11$ kW, $P_{CP} = 22$ kW, $P_{CP} = 50$ kW, and $P_{CP} = 150$ kW and for an increasing number of EVs. Consequently, the DFs are calculated for the aforementioned charging powers for up to 500 CPs. Finally, a curve fitting algorithm from *MATLAB* [89] is applied to determine the DFs between $P_{CP} = 3.7$ kW and $P_{CP} = 150$ kW with $P_N = 1$ kW steps. [83]

The resulting DFs are shown in Figure 3.4 (p. 35) as a "General Urban" DF curve. These DFs are applied to calculate the load power P_{load} of the CPs. To validate their general applicability, these used DFs "General Urban" are compared with area specific DFs.

The statistical driving data published in [88], on which the DFs "General Urban" are generated, does not differentiate between the area type in which the vehicle is driven. Later on, an update of the statistical data is published in [90], which differentiates the statistical driving data into the following seven area types defined by [91]. The area types are differentiated according to the density of the population.

1. Urban Region: Metropolis,
2. Urban Region: Regiopolis, Large City,
3. Urban Region: Medium-sized City, Urbanised Area,
4. Urban Region: Small-town Area, Village Area,
5. Rural Region: Central City,
6. Rural Region: Medium-sized City, Urbanised Area,
7. Rural Region: Small-town Area, Village Area

With the focus on urban MV grids and specifically MV grids in cities, the area types 4 - 7: Urban Region: Small-town Area, Village Area; Rural Region: Central City; Rural Region: Medium-sized City, Urbanised Area, and Rural Region: Small-town Area, Village Area are excluded from the upcoming analysis.

The recently acquired DF curves for the three urban regions: "Metropolis", "Large City" and "Medium-sized City", which are generated based on the statistical driving data published in [90] are set in comparison with the fourth DF curve "General Urban" in Figure 3.4 (p. 35). Similar to the "General Urban" DF curve, the DFs for the nominal charging powers $P_{CP} = 3.7$ kW, $P_{CP} = 11$ kW, $P_{CP} = 22$ kW, $P_{CP} = 50$ kW and $P_{CP} = 150$ kW are illustrated for the three urban area types.

In contrast to the transformer planning perspective, where the considered number of CPs may exceed 500 CPs, the considered number of CPs in the feeder planning perspective is definitely smaller. Therefore, a zoomed-in section of the graph is inserted in the top right corner of the figure. On one hand, the number of CPs per MV feeder usually exceeds 100 CPs and on the other hand, the DF curves tend to flatten starting from 400 CPs. Hence, the displayed number of CPs in the zoomed-in section is between 200 and 400 CPs.

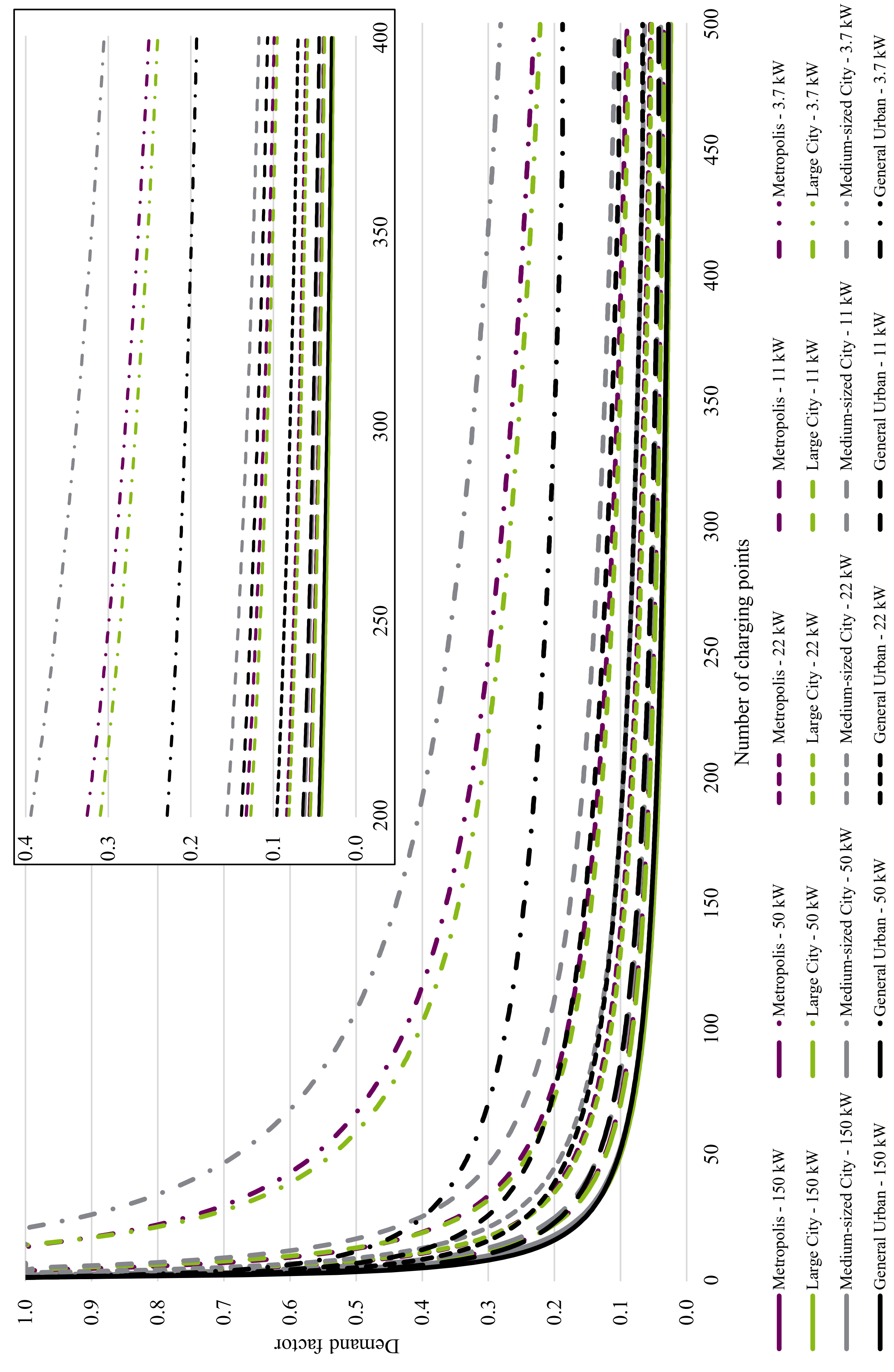

Figure 3.4: Demand factors for P_{CP} = 3.7 kW, P_{CP} = 11 kW, P_{CP} = 22 kW, P_{CP} = 50 kW and P_{CP} = 150 kW for Metropolis, Large City, Medium-sized City and General Urban for up to 500 charging points

Figure 3.4 shows that the “General Urban” DF curve type matches the three urban DF curves to a great extent. Even though there is a minor discrepancy between the DF “General Urban” curve for $P_{\mathrm{CP}} = 3.7$ kW and the remaining three DF curves, this discrepancy shrinks for the higher charging power. Hence, the validity of the “General Urban” DF can be confirmed.

It is noted that the DF values of the charging power $P_{\mathrm{CP}} = 3.7$ kW differ slightly between the four DF curves. This difference stems from the sensitivity of the lower charging powers to the statistical driving behaviour in these areas and the random initiation of the driving profiles in generating the curves. Nevertheless, the differences between the DF curves decrease with increasing the charging power and can be neglected for the charging powers $P_{\mathrm{CP}} \geq 22$ kW.

In addition, Figure 3.4 shows that the DFs for “General Urban” overlap the DFs for the three urban regions for the five charging powers. To generate generally valid urban MV PGs and to perform analysis independent of the specific urban area type, the DFs for “General Urban” are used in calculating the load power P_{load} for EVs.

After determining the DFs for EVs, the method of calculating the load power P_{load} needs to be specified. Since there is an assumed distribution of the charging powers and a division of the CPs into prCPs and puCPs (see Table 3.1), several methods for calculating the load power P_{load} have arisen. A general method for calculating the load power is given in equation (3.17). Evidently, the load power P_{load} per load unit depends on three factors: the considered nominal load power P_{N}, the considered number of loads n and the DF of the corresponding nominal load power for the specific number of loads identified as $DF_{\mathrm{n,P_N}}$.

$$P_{load} = P_{\mathrm{N}} \cdot DF_{n,\mathrm{P_N}} \tag{3.17}$$

In the case of the CP load power $P_{\mathrm{load,CP}}$, the aforementioned general equation needs to be adjusted as there are varying DFs in calculating the CP load. The DF of EVs depends not only on the considered charging power of the CP but also on the corresponding number of CPs per charging power. According to these two varying parameters, different DF values (as shown in Figure 3.4) can be applied in calculating the CP load power $P_{\mathrm{load,CP}}$.

As for the charging power considered in determining the DF, either the nominal charging power per CP P_{CPi} or the effective charging power over all CPs P_{eff} can be considered. The effective charging power can be calculated according to equation (3.18). The same applies to the considered number of CPs in determining the DF, as either the individual number of CPs per charging power n_{CPi} or the total number of CPs in the grid Σn_{CP} can be considered.

$$P_{\mathrm{eff}} = \frac{\sum(P_{\mathrm{CPi}} \cdot n_{\mathrm{CPi}})}{\sum n_{\mathrm{CPi}}} \tag{3.18}$$

The combination of these two variants per parameter results in four possible DF values that can be applied in calculating the CP load power. The four possible DF values and their arrangement are summarised in Table 3.2.

Table 3.2: The arrangement of the parameters considered in determining the demand factors of the charging points (No. = number)

		Charing power P_{CP}	
		Nominal P_{CPi}	**Effective P_{eff}**
No. of charging points n_{CP}	**Individual (n_{CPi})**	$DF_{P_{CPi},n_{CPi}}$	$DF_{P_{eff},n_{CPi}}$
	Total (Σn_{CP})	$DF_{P_{CPi},\Sigma n_{CP}}$	$DF_{P_{eff},\Sigma n_{CP}}$

Adjusting the general equation of calculating the load power (equation (3.17)) according to the four possible DF values ($DF_{P_{CPi},n_{CPi}}$, $DF_{P_{CPi},\Sigma n_{CP}}$, $DF_{P_{eff},n_{CPi}}$, and $DF_{P_{eff},\Sigma n_{CP}}$) given in Table 3.2, results in four possible methods for calculating the CP load power. These methods are listed in equation (3.19), equation (3.20), equation (3.21) and equation (3.22). [77]

$$P_{\mathrm{load,CP}} = P_{\mathrm{CPi}} \cdot DF_{\mathrm{P_{CPi}},\mathrm{n_{CPi}}} \tag{3.19}$$

$$P_{\mathrm{load,CP}} = P_{\mathrm{CPi}} \cdot DF_{\mathrm{P_{CPi}},\Sigma\mathrm{n_{CP}}} \tag{3.20}$$

$$P_{\mathrm{load,CP}} = P_{\mathrm{CPi}} \cdot DF_{\mathrm{P_{eff}},\mathrm{n_{CPi}}} \tag{3.21}$$

$$P_{\mathrm{load,CP}} = P_{\mathrm{CPi}} \cdot DF_{\mathrm{P_{eff}},\Sigma\mathrm{n_{CP}}} \tag{3.22}$$

A sensitivity analysis of these four calculation methods of DFs is performed in [77]. The first calculation method (equation (3.19)) considers each of the charging powers separately with their respective number and their respective DFs with the assumption that each charging power is a separate load type. The second and the third calculation methods propose considering a common factor over the CPs, whether it is the total number of CPs in the grid Σn_{CP} (equation (3.20)) or an effective charging power P_{eff} (equation (3.21)). These assume that the CP load can be collectively modelled by grouping the CPs either by considering the total number of CPs in the grid or by considering an effective charging power. The fourth calculation method given in equation (3.22) regards the CP load of the different charging powers as a single load type by considering both an effective charging power over all charging powers and the total number of charging points in the grid. [77] concludes that the consideration of an effective average charging power and the corresponding DF for the total number of CPs in the grid is the most practicable and plausible calculation method. Hence, the load power for CPs $P_{load,CP}$ follows this calculation method demonstrated in equation (3.22). Even though the analysis in [77] is performed for LV grids, the final conclusion can be applied to all voltage levels. The above-given calculations are performed from the transformer planning perspective. For the feeder planning perspective, the number of CPs in the feeder and the effective charging power are calculated per feeder.

3.5 Modelling of the Heat Pump Load

Similar to the EV load, the HP load is also associated with uncertainties of location and discrepancies in the load power. Hence, the following two sections present a method for modelling the HP load, starting with allocating the HPs in a specific MV grid and continuing with specifying their load power.

3.5.1 Scaling Down and Distribution of Heat Pumps

The process of scaling down and distribution of HPs in the MV grids corresponds to that of the EV load. The differences between the process for HP and EV load are the distribution factors applied in the different scaling down levels. Nevertheless, it follows the same scaling down levels shown in Figure 3.1 from the country level to the state level to the city level and then to the district and the street level.

In the first step of scaling down the number of HPs from the country level to the state level, the number of HPs in the scenarios selected in section 2.2.2 are distributed proportionally to the current number of HPs per state published in [92]. Since the adoption and integration of HPs depend primarily on the residential building structure, it is assumed that the residential building structure remains unchanged among the states. Hence, it is assumed that the ratio of integration of HPs among the states remains constant over the years. [49]

As the number of HPs per state is determined, this number is scaled down further on the city level. According to the general framework conditions of HPs mentioned in section 2.2.1, it is assumed that HPs are mainly installed in detached houses with one or two households. Hence, the number of HPs is scaled down in the cities in relation to the number of detached houses. [49]

The scaling down from the city level to the district level also relies on the number of detached houses with one or two households. Based on the census 2011 [93] database of the detached houses per district, the number of HPs is scaled down from the city level to the district level. [49]

The final scaling down step from the district level to the city level and the street level considers the market and geo-data [94] of detached houses and household net income. In which, a Saint-Laguë method described in [95] is applied to determine the number of HPs in the city and the street level. [49]

To fully apply the aforementioned scaling down process from the country level to the street level, geo-economical data about the streets in the investigated MV grid need to be available. In most cases, acquiring this data in this depth of detail is complicated. Hence, an alternative approach is developed to determine the number of HPs per MV grid without resorting to the geo-economical data.

Similar to the CPs, the spread of HPs into the grids correlates to the buildings supplied by the grid. Consequently, the number of HPs per MV grid is calculated in relation to the number of building connections supplied by the MV grid. By analysing the number of HPs in several LV grids, a linear relation is derived between the number of HPs in a specific year and scenario and the present number of building connections in the LV grid [40].

These linear relations are then used to determine the total number of HPs in a MV grid based on the number of building connections in the grid. Finally, based on the number of building connections in each of the downstream LV grids, the number of HPs per secondary substation is determined.

3.5.2 Power Assumptions and Demand Factor Calculation for Heat Pumps

After determining the number of HPs per secondary substation in a MV grid, the power value per HP P_{HP} and the DF corresponding to the number of HPs are required to calculate the load power to be modelled in the MV grid. Based on the general framework conditions of HPs presented in section 2.2.1, the assumed power values of HPs are listed in Table 3.3. As the table shows, three HP models are considered, namely, HP model 1 with $P_{HP} = 3$ kW, model 2 with $P_{HP} = 6.5$ kW and model 3 with $P_{HP} = 9$ kW.

HP model 1 assumes that the HP will not be subject to turn-off periods enforced by the DSO and that it does not include an additional electrical heating element. When the HPs are subject to turn-off periods, they must be bigger dimensioned, namely, with an electric power of $P_{HP} = 4.0$ kW. As for the HP model 3, it is assumed that the HP is subject to turn-off periods enforced by the DSO and that the model includes an additional electrical heating element. Therefore, HP model 3 amounts to $P_{HP} = 9$ kW. HP model 2 is a middle distribution between HPs subjected to turn-off periods ($P_{HP} = 4.0$ kW) without an additional electrical heating element and HPs subjected to turn-off periods and equipped with an additional electrical heating element ($P_{HP} = 9.0$ kW).

Since the dimensioning of a HP differs according to the heat demand of the household, the consideration of three HP models ensures covering a wide spectrum of HP dimensions. [96]

Table 3.3: The power value assumptions for the three heat pumps models with the differences between the models

Heat pump	Power value	Turn-off periods	Electrical heating element
Model 1	3.0 kW	No	No
Model 2	6.5 kW	Yes	50 % with, 50 % without
Model 3	9.0 kW	Yes	Yes

Figure 3.5 (p. 40) shows the DFs for up to 500 HPs. In contrast to the DFs for CPs, this figure shows that the DFs for HPs do not fall rapidly for an increasing number of units. Furthermore, the DF curve flattens relatively quickly in comparison to the DF curves for CPs.

Since the operation of HPs depends heavily on the outdoor temperature, the HPs in a grid operate nearly simultaneously depending on the outdoor temperature present in the grid area. Hence, the DFs for HPs do not decrease drastically with the increasing number of HPs. Furthermore, the DFs are not dependent on the power value of the HP.

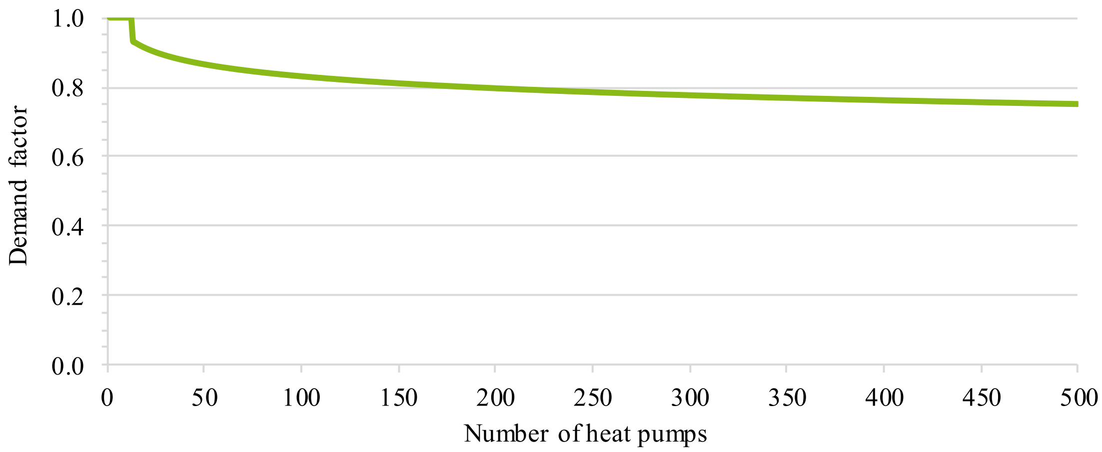

Figure 3.5: Demand factors for up to 500 heat pumps based on [97]

3.6 Modelling of the Photovoltaic Systems

Similar to the load modelling procedures of the new loads explained in the previous two sections, a generally applicable procedure for modelling the DG is needed for the grid planning. The procedure needs to scale down the chosen countrywide scenarios for the DG (section 2.3.2) to power values to be considered in the individual MV grids.

3.6.1 Scaling Down and Distribution of Photovoltaic Systems

For the new loads, the concrete number of the CPs and the HPs are determined per MV grid by applying the scaling down and distribution methods previously presented. In contrast, there is difficulty in scaling down the forecasted PV power from the countrywide scenarios to the respective grid level. Moreover, the issue of the voltage level, at which the PV system is integrated, must be considered, as the investigated scenarios (section 2.3.2) provide limited information in this regard.

In the first step, the installed PV power per voltage level is determined on the level of the Federal Republic of Germany from the market data register[9] [98] and then set in relation to the total actual installed PV power in the Federal Republic of Germany for all voltage levels. This distribution of the installed PV power per voltage level represents the potential for future installations in terms of both geographical and technical constraints.

[9] The core energy market data register is a comprehensive, official register of the electricity and gas market for use by the authorities and participants in the energy (electricity and gas) sector.

Since the choice of the installation site, especially for DG, is dependent on weather conditions such as radiation intensities and the space availability in rural areas versus urban areas, it can be assumed that these constraints remain constant over the investigated period of time. Hence, the current distribution of the installed PV power per voltage level is extrapolated over the investigation years.

While PV penetration in rural areas is expected to occur mainly in the MV level, the PV penetration in urban areas is expected mostly in the LV level, specifically at detached houses. Therefore, the scaling down process focuses on the integration of the PV systems in the downstream LV grids supplied by the investigated MV grid.

As a first step, the ratio of the installed PV power in the LV $v_{\mathrm{PV,LV}}$ is calculated as a relation between the installed PV power in the LV $P_{\mathrm{PV,LV}}$ and the total installed PV power in the country $P_{\mathrm{PV,country}}$. This is done according to equation (3.23).

$$v_{\mathrm{PV,LV}} = \frac{P_{\mathrm{PV,LV}}}{P_{\mathrm{PV,country}}} \tag{3.23}$$

By applying the ratio of the installed power in the LV $v_{\mathrm{PV,LV}}$ to the chosen scenarios, the PV power in the LV at a specific investigation year $P_{\mathrm{PV,LV,y}}$ is determined at the country level. The PV power in the LV at a specific investigation year $P_{\mathrm{PV,LV}}$ is then scaled down from the country level to determine the PV power in the downstream LV grids supplied by the investigated MV grid. Similar to the scaling down process for the new loads, the $P_{\mathrm{PV,LV,y}}$ is scaled down from the country level to the state level, to the city level, to the district level and to the street level. The PV power is then summed for all the streets in a certain LV grid to determine the PV power per downstream LV grid supplied by the investigated MV grid.

For the scaling down of PV power in the LV from the country level to the state level and the city level, the method explained in [99] is executed. In this method, several distribution factors are considered and set in relation to the total available value of this factor on the certain scaling down level. Among the distribution factors are the surface area, the number of buildings, and the potential of PV. As a result, the expected PV power is calculated on the state level $P_{\mathrm{PV,LV,state,y}}$ and the city level $P_{\mathrm{PV,LV,city,y}}$ for each of the two scenarios and the three investigation years.

To further scale down the PV power in the district and the street level, detached houses are identified as the primary installation site for PV systems in the LV. Therefore, the number of detached houses is considered a distribution factor for scaling down the PV power further on the district level and the street level. This factor is derived from the quotient of the number of detached houses per level of scaling down in relation to the number of detached houses at the higher level. Hence, the number of detached houses on the state level k_{state}, on the city level k_{city}, and on the street level k_{street} are required.

This approach is repeated iteratively from the city level to the district level and to the street level. Consequently, the forecasted PV power on the district level $P_{\mathrm{PV,LV,district,y}}$ and the street level $P_{\mathrm{PV,LV,street,y}}$ for a certain investigation year are calculated according to equation (3.24) and equation (3.25) respectively.

$$P_{\mathrm{PV,LV,district,y}} = \frac{k_{\mathrm{district}}}{k_{\mathrm{city}}} \cdot P_{\mathrm{PV,LV,city,y}} \tag{3.24}$$

$$P_{\mathrm{PV,LV,street,y}} = \frac{k_{\mathrm{street}}}{k_{\mathrm{district}}} \cdot P_{\mathrm{PV,LV,district,y}} \tag{3.25}$$

The forecasted PV power on the street level is then consolidated per downstream LV grid. This is modelled at the respective secondary substations in order to investigate the influence of the PV power on the respective MV grid.

3.6.2 Power Assumptions and Demand Factor Calculation for Photovoltaic Systems

In contrast to the new loads, separate power assumptions for the individual PV systems are not required. Since the forecasted PV power is determined on the street level by equation (3.25), this value can be consolidated per secondary substation and used directly to model the PV power at the peak generation operating point in the MV grids.

Further differentiation between the PV systems and the new loads arises in considering the DF for PV systems. Unlike the new loads, the feed-in power per PV system does not decrease with the increasing number of units, as the feed-in power is dependent on the weather conditions, not the number. Nevertheless, publications such as [39] introduce a depreciation factor for the feed-in power by considering factors such as the PV system orientation. These proposed depreciation factors are listed in Table 3.4 and are applied accordingly.

Table 3.4: The assumed depreciation factors for the photovoltaic systems in the low-voltage level for the planning of the medium-voltage grids based on [39]

Planning perspective	Depreciation factor	Remarks
Feeder	0.76	Averaged orientation and degradation of the feed-in power
Transformer	0.76	Averaged orientation and degradation of the feed-in power

By modelling the elements of the energy transition in the MV grids with their respective power assumptions and their corresponding DFs, the MV grids exhibit the future supply task following the chosen scenarios. At this point, the ability of the MV grid to safely take on the future supply task needs to be examined in order to avoid grid limit violations.

3.7 Identification of the Grid Limits

The aforementioned integration of the new loads and DG into the grid may cause a non-standard-compliant grid operation. In order to sustain a failure-free and standard-compliant MV grid operation, a load flow analysis is performed to ensure maintaining the voltage range and the equipment loading. A comprehensive set of standards, regulations, and guidelines must be considered to guarantee a standard-compliant operation of the MV grid.

The node voltage V_N must be maintained within the permissible voltage range specified by the standards. Violating this voltage range can result in equipment damage and/or outage. Violating the upper voltage range (over-voltage) can lead to failure(s) in the equipment insulation and current surges, whereas a voltage level lower than the permissible voltage range (under-voltage) can be non-sufficient for starting motors and operating machinery. Additionally, the equipment loading cannot exceed the maximum loading of the equipment. Exceeding the equipment's permissible loading causes overheating of the conductors, which can lead to damage of the insulation and – in some cases – to a series of cascaded failures.

In addition to the voltage and the loading limits, the short-circuit current must remain within the current interruption capacity of the circuit breakers. Otherwise, the circuit breakers would not be capable of interrupting the current in case of a short-circuit, which would lead to serious equipment damage. Besides the circuit breakers, the equipment in the grids can withstand a certain short-circuit current for specific time intervals. If the short-circuit current value exceeds its limit or continues for longer time periods, the equipment can suffer permanent damage.

For the calculation of the short-circuit currents, specific parameters (such as the neutral point handling and the short-circuit capacity at the HV side of the HV/MV substation transformer) are required. As these parameters can differ significantly from a MV grid to another, the short-circuit current calculation is waived to maintain a generally applicable planning methodology and consequently generally valid PGs. Moreover, unlike the voltage level violations and the equipment overloads, the short-circuit currents do not represent a pressing issue for the DSOs, as the short-circuit levels are within the limits in the public supply distribution grids. Nevertheless, it is advised to perform a short-circuit current calculation according to [100] with the grid-specific parameters after planning the grids with the elements of the energy transition.

Besides the short-circuit currents, the reliability of the grid needs to be determined. Reliability is defined as the "probability that an electric power system can perform a required function under given conditions for a given time interval" [101]. Similar to the short-circuit current calculation, the reliability calculation requires grid-specific parameters. In addition, the consideration of the single contingency case in the permissible loading of the equipment (see section 3.7.2, p. 45) guarantees adequate reliability in the grids. Therefore, the reliability calculation is not performed. Nevertheless, it is investigated in a simplified way in the alternative assessment model (see section 3.10.2, p. 62).

3.7.1 Permissible Voltage Range

The voltage range V_R of European three-phase power grids must comply with the *DIN EN 50160* [102], which represents a fundamental parameter in designing the grid equipment. It specifies that the slow voltage change ΔV in the grid must be within the voltage range to ensure a standard compliant operation of the equipment at the end consumers and to prevent any damage caused by over-voltage or under-voltage. The specified voltage range extends from a minimum voltage V_{min} to a maximum voltage V_{max} according to equation (3.26).

$$0.9 \cdot V_n = V_{min} \leq V_N \leq V_{max} = 1.1 \cdot V_n \quad (3.26)$$

The voltage range applies to the end consumers connected in the MV grids and the downstream LV grids and is not specific to a certain voltage level. Generally, the DSOs divide the voltage range between the LV level and the MV level in their company specific planning and operation guidelines. Hence, this allowed voltage range cannot be completely used for the MV level. This means that in the peak load operating point and the peak generation operating point, the maximum voltage change $\Delta V/V_n = \pm 10$ % must be divided between the LV level and the MV level.

Figure 3.6 shows a typical division of the voltage range between the LV level and the MV level. At the top of the figure, an exemplary grid is illustrated parallel to the permissible voltage range starting at the HV/MV transformer and extending over a MV grid and a LV grid with their connected loads and DG.

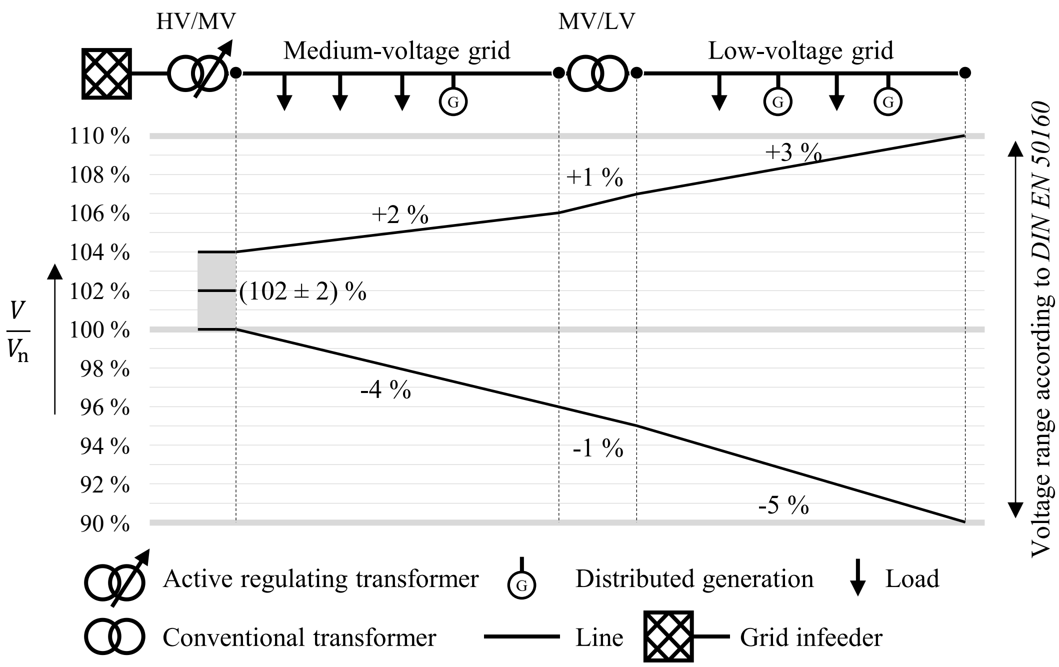

Figure 3.6: Permissible voltage ranges for medium voltage and low voltage grids according to [72], [102], [103]

The voltage setpoint is determined to be V_{set}/V_n = 102 % with the regulating range of the HV/MV transformer set to V_R/V_n = 2 % as a voltage change due to the tap changes. Herein, the following voltage range boundaries are determined in this work.

In the peak load operating point with the minimum transformer voltage regulation V_R/V_n = -2 %, a node voltage of V_N/V_n = 100 % is available at the MV busbar. Based on the node voltage of the MV busbar, a voltage change of $\Delta V/V_n$ = -4 % is allowed in the MV grid at the peak load operating point. Consequently, a total voltage change of $\Delta V/V_n$ = -6 % is calculated in the downstream LV grid including the MV/LV transformer.

As for the peak generation operating point with the maximum voltage regulation of the HV/MV transformer V_R/V_n = 2 %, a node voltage of V_N/V_n = 104 % becomes available at the MV busbar. Here, the allowed voltage change in the MV grid is set to be $\Delta V/V_n$ = +2 %. This leaves a total voltage change of $\Delta V/V_n$ = +4 % in the downstream LV grids including the MV/LV transformer. In both operating points, a voltage change of $\Delta V/V_n$ = ±1 % is assumed over the MV/LV transformer.

3.7.2 Permissible Loading of Equipment

Similar to any technical device, the equipment installed in the grids has limits for their safe and reliable operation. In the specific case of grid equipment, this limit refers to the maximum thermal loading set by the applicable standards and/or the datasheet of the equipment manufacturer. Exceeding the maximum thermal loading of the equipment is referred to as “overload”. The main current-carrying equipment in the grids are lines and transformers and their permissible loading is explained in the following.

Lines

The general term line is used in this context to refer to overhead lines and underground cables. The *DIN EN 0276-1000:1995-06* [104] specifies that the cross-section area c of the underground cables must be selected so that the conductor is not heated above the permissible operating temperature at any point during the operation. In addition, further factors must be considered by the loading of lines such as 1) the structure and the material properties of the conductor and insulation, 2) operating conditions, 3) the layout conditions such as bundled or in series and 4) the ambient conditions including the soil temperature and the solar radiation. The consideration of the reduction factors reduces the ampacity of the lines [105]. Extensive tables for the line ampacity can be found in [106] and the tables for reduction factors are found in [104]. Hence, the maximum permissible current I_{max} of the line differs from the rated thermal current loading I_{th} according to the aforementioned factors, which are then converted into calculable ampacity reduction factors. The maximum permissible current of lines is determined according to equation (3.27) in the contingency-free grid operation.

$$I_{\max} \leq I_{\mathrm{th}} \text{ in a contingency-free operation} \tag{3.27}$$

The MV grids must be dimensioned with a certain reserve in order to continue standard-compliant operation in the case of a single equipment failure commonly referred to as a single outage occurrence or a single contingency[10]. It is assumed that at the peak load operating point, the lines can be loaded according to equation (3.28) in a single contingency case. According to section 3.1, the MV grids have a common radial ring topology. Hence, the lines can be loaded up to I/I_{th} = 60 % in the contingency-free operation.

$$I_{\max} \,/\, I_{\mathrm{th}} \leq 120~\% \text{ in a single contingency operation} \tag{3.28}$$

Transformers

With the focus on MV grids, the transformers in the context refer to the HV/MV transformers located in primary substations. The *DIN EN 60076-1* [108] specifies the general operating conditions for transformers in order to obtain the intended rated power S_{r} in continuous operation without exceeding the transformer loading $S_{\max}/S_{\mathrm{r}}$ limit. Additionally, the transformer accessories (e.g., tap-changers and auxiliary devices) must be correctly dimensioned to not restrict the transformer rated power S_{r}. Under certain operating conditions, the transformer can be loaded over its rated power for a short period of time as the continuous overloading of the transformer fastens the ageing of its insulation. *IEC 60076-7* [109] presents the calculation methods used to determine the permissible loading for liquid-filled and dry transformers, respectively.

Alike lines, the single contingency case must be considered for dimensioning the transformers. Hence, the common constellation in primary substations is the installation of two transformers of the same rated power. In a single contingency operation, a single transformer can be loaded up to $S_{\max}/S_{\mathrm{r}} \leq 120$ %. Thus, a maximum loading of $S_{\max}/S_{\mathrm{r}}$ = 60 % for each of the two transformers is allowed for the contingency-free operation.

As for the MV/LV transformers installed in the secondary substations, they are considered a part of the LV grid planning. Hence, they are not modelled in the investigated MV grids and their loading is not examined while determining the overloaded equipment in the MV grids.

By identifying the grid limit violations according to the grid limits explained in this section, remedy measures need to be implemented. To remedy these violations, either conventional measures or innovative technologies can be applied. These are explained in detail in the upcoming section 3.8 (p. 47) and section 3.9 (p. 50).

[10] Single-outage occurrence or a single contingency is defined as "outage occurrence caused by only one system component" [107].

3.8 Conventional Planning Measures

The term "conventional planning measures" refers to the current state of technology that is widely implemented by DSOs. Since the strategic grid planning methodology focuses on the required measures for the future grid supply task, the proposed conventional planning measures are executed solely for the future MV grids after modelling the elements of the energy transition and identifying a grid limit violation. Therefore, the ongoing renewal planning in terms of asset management, modernisation, and grid expansion is not considered. The conventional planning measures are executed across the investigation years so that a single measure remains sufficient for the load and DG development in the following investigation years. In this section, both the secondary substations and the customer substations are referred to as stations, as they are treated equally as load grid nodes when it comes to the planning measures.

3.8.1 Line Measures

The performed line measures are applied for solely overloaded lines in existing line routes. Accordingly, the introduction of new line routes between the stations is ruled out to enforce a unified planning methodology for all MV grids. The line cross-section areas $c = 150$ mm^2, $c = 185$ mm^2, $c = 240$ mm^2 and $c = 300$ mm^2 are used with an Aluminium conductor and cable type NA2XS2Y. In case the line cross-section area $c = 300$ mm^2 is insufficient for remedying the line overload, two parallel lines with an equal cross-section area are laid starting with the cross-section area $c = 150$ mm^2 and then moving to larger line cross-section areas. The line measures can be differentiated according to the specific implementation as follows:

Line replacement

Generally, several approaches can be applied by DSOs in terms of line replacement in strategic grid planning. The approaches for line replacement can consider several factors, such as the lifetime of the line, the frequency of faults of the line or the insulation material type. However, this specific line data is not available across all the investigated MV grids from the different DSOs (see section 4.1.1, p. 67). Therefore, an alternative line replacement approach is executed to maintain unified line replacement measures.

The line replacement is performed based on a simplified line condition assessment, which depends on the cross-section area of the existing line and its insulation material type. If the overloaded line section has a cross-section area $c < 120$ mm^2 or an oil or paper insulation material (e.g., NAKBA), it is assumed that this line section is approaching the end of its lifetime and is going to be replaced within the asset management activities. In this case, a line replacement is performed for the grid planning. Moreover, if a short line section of a modern line type is located between two line sections that need to be replaced, the short line section is replaced together with the outer two line sections to reduce the joints in the line route. This is done to avoid potential failures occurring at line joints.

Line reinforcement

In addition to line replacement, a line reinforcement can be executed. The line reinforcement is carried out by laying a line of the same cross-section area parallel to the existing overloaded line. These parallel lines need to be of an equal cross-section area to avoid an unequal loading of the two parallel lines. The line reinforcement is carried out according to the following cases:

If the line starting from the primary substation and extending to the first station in the MV ring is overloaded, a line of an equal cross-section area is laid in parallel. The newly laid parallel line can be connected to the same existing MV air-insulated switchgear. In this case, no further switchgear is required at the primary substation. If the overloaded line is connected to the primary substation using gas-insulated switchgear, additional switchgear will be required to connect a parallel line. By considering the cost and space restrictions for the newly needed switchgear, it can be advised to replace the existing overloaded line instead of reinforcing it. To enforce a consistent planning approach for all MV grids, it is assumed that the overloaded lines are connected using air-insulated switchgear and can be reinforced with parallel lines of an equal cross-section area.

If the line connecting two stations or two joints is overloaded and is not to be replaced, a line of the same cross-section area can be laid in parallel. If the line is between two stations, the newly laid parallel line can be connected to the MV busbars of the stations on both sides. Accordingly, the MV panel, including the busbars, needs to be examined before the newly laid parallel line is connected. If the overloaded line section is between two joints, the line is connected from both sides.

Construction of a new feeder

If the load in a MV ring increases significantly, a new feeder can be constructed. Thus, the new feeder can partially take on the load from the existing overloaded MV ring by shifting some station(s) from the overloaded MV ring to the newly constructed feeder. The newly constructed feeder can be constructed starting from the primary substation to form a new MV ring, independent of the existing MV rings. Otherwise, the newly constructed feeder can be laid to a station in the existing overloaded MV ring as a fortification branch to the existing MV ring. In both cases, the newly constructed feeder is connected to a separate MV switchgear in the primary substation.

For executing line measures, no reduction factors are considered. This is performed under the assumption that the lines are dimensioned so that they are not permanently loaded with their rated thermal current $I < I_{\mathrm{th}}$ Moreover, the peak load and the peak generation operating points used for dimensioning the lines correspond to an extreme grid situation that does not necessarily occur for a long period of time. For specific planning of a MV grid, it is, however, recommended to consider the corresponding reduction factors [104] for dimensioning the lines.

3.8.2 Primary Substation Transformer Measures

Besides the line measures, increasing the primary substation capacity is an essential measure for the MV grid planning. Starting from this section, the term "transformer(s)" refers solely to the HV/MV substation transformer(s).

The general constellation in primary substations is two parallel transformers of an equal rated apparent power S_r each connected to a busbar. However, each primary substation has individual characteristics in terms of the installed rated apparent power S_r, available space, number of switchgear and insulation (i.e., air- or gas-insulated). Therefore, there are several possibilities for increasing the primary substation capacity.

Transformer replacement

According to the space restrictions, the existing transformers can be replaced by two transformers of an equally higher rated apparent power and impedance, to avoid circulating currents between the transformers. In this case, no extra space is required to install further busbars or switchgear. However, the short-circuit currents at the busbars and in the MV grid need to be recalculated to ensure their compliance with the installed switchgear. Furthermore, the equalising currents between the transformers from opposing primary substations need to be examined in the case of a radial MV grid connecting two different primary substations.

Transformer reinforcement

If there is enough space in the primary substation, the existing transformers can be reinforced with an additional transformer of the same rated apparent power. Here, the newly installed transformer gets connected to a new busbar and supplies one or several feeders, thus reducing the loading of the existing transformers. In addition to the equal rated apparent power S_r, the impedance of the newly installed transformer must equal the impedance of the already existing transformers. Moreover, the short-circuit currents at the busbars and in the MV grid need to be recalculated to ensure their compliance with the installed switchgear.

3.8.3 Transformer Voltage Regulation Measure

The transformer voltage regulation (TVR) refers to the voltage regulation of the HV/MV transformer at the MV busbar. This is done during the operation by changing the voltage setpoint of the transformer. Depending on the current voltage in the grid, the TVR can either increase or decrease the node voltage on the MV busbar. Consequently, this influences the node voltages both in the MV grid and in the downstream LV grids. Since the voltage regulating HV/MV transformers have already been in service for years, this measure is considered a conventional planning and operation measure.

There is more than one concept for TVR depending on the data used for changing the voltage setpoint of the HV/MV transformer.

One of the concepts operates by regulating the voltage according to the node voltage of the MV busbar. Another concept for TVR depends on voltage measurement sensors in the MV grid to regulate the voltage accordingly. Herein, a basic concept of TVR is adopted in which the voltage regulation depends on a predefined voltage set point. Thus, the costs for this measure can be neglected, as they merely represent the operational costs of a technician adjusting the voltage set point. [40]

According to section 3.7.1, the voltage set point is at $V_{set}/V_N = 102\ \%$ with a control range of $V_R/V_N = \pm 2\ \%$ through TVR. Within the MV grid planning, it is assumed that the voltage set point can be adjusted in steps of $V/V_N = \pm 0.5\ \%$, which gives a total of nine steps for TVR. With the static adjustment of the voltage set point, the node voltages must be checked for the peak load as well as the peak generation operating points.

As an alternative to the explained conventional planning measures, innovative planning technologies can be applied to remedy the occurring grid limit violations.

3.9 Innovative Planning Technologies

As an alternative to the conventional planning measures explained in section 3.8, innovative planning technologies can be implemented to remedy grid limit violations. The term “innovative planning technologies” refers to the newly developed technologies that are selectively implemented in MV grids and still not deployed in the complete grid area. Since the conventional planning measures are well established, conventional planning represents the reference planning alternative[11] (PA) in comparison to innovative planning. The comparison between the PAs is performed according to the assessment model presented in section 3.10 (p. 60). Depending on the assessment, the usability of the innovative planning technologies is determined. If the grid limit violations cannot be completely eliminated by one of the innovative planning technologies, the conventional planning measures are supplementarily implemented.

Table 3.5 (p. 51) gives an overview of the applicability of the aforementioned conventional planning measures in addition to the forthcoming innovative planning technologies. The table displays the voltage level of deployment as well as the use cases for the application. The use cases can compromise an overload of the equipment or a voltage violation either as an under-voltage or an over-voltage. Similar to the conventional planning measures, the innovative planning technologies are applied to remedy the occurring grid limit violations. Unlike the innovative planning technologies (e.g., LM), the conventional planning measures are voltage level specific. This means that these measures are deployed at a certain voltage level to remedy the violations within this voltage level.

[11] Planning alternative is a final grid model in the year 2050 for a specific scenario and heat pump model where the expected grid violations are resolved either by solely conventional planning measures or with one of the innovative planning technologies in combination with conventional planning measures.

In contrast, LM operates by regulating the CPs and the HPs connected in the downstream LV grids to remedy grid limit violations occurring in the MV grids. In addition to equipment overloading, ES can remedy over-voltage and under-voltage violations, whereas LM can only remedy under-voltage violations.

Table 3.5: Overview of the use cases for conventional planning measures and innovative planning technologies ("✓": applicable, "-": not applicable) [96]

Measure/Technology	Voltage level of deployment	Use case of the measure		
		Overload	Under-voltage	Over-voltage
Line	MV	✓	✓	✓
Primary substation transformer	MV	✓	-	-
Transformer voltage regulation	MV	-	✓	✓
Switching	MV	✓	✓	✓
Load management	LV	✓	✓	-
Energy storage	MV	✓	✓	✓

The innovative planning technologies shown in Table 3.5 are chosen to be relevant to the challenges at hand. Other innovative planning technologies that are solely applied to the HV level (such as flexible alternating current transmission [110], or power flow control devices [111]) are not considered. Furthermore, the innovative technology feed-in management, is not considered, as the integration of DG is found to have an insignificant impact on the MV grids in comparison to the impact of the new loads on the MV grids. The impact of the DG in comparison to the new loads is analysed in detail in section 4.2 (p. 72). Another relevant technology can be reactive power management. After modelling and applying reactive power management in several MV grids, it has proven to be ineffective. Since the peak load operating point is more severe on the grid limits (the influence of DG is discussed in section 4.2 p. 72), reactive power management cannot be a viable solution due to two main reasons. The first reason is that the integration of new loads into the grid results predominantly in equipment overloading. Hence, a review of the voltage limit distribution between the LV level and the MV level is recommended (see 6th PG, section 5.1.6, p. 108). The second reason is that, by adjusting the power factor of the CPs to be lagging to increase the reactive power in the grid to compensate for the voltage drop, the drawn current increases. The increasingly drawn current contributes further to the equipment overloading in the grid to benefit the node voltage, which does not technically require the voltage increase since it is within the limits before applying reactive power management. Therefore, it is not further investigated [96]. Other voltage regulation measures (such as on load tap changing transformers) are not investigated, as the urban MV grids do not exhibit voltage level violations.

3.9.1 Decentralised Grid Automation

Decentralised grid automation (DGA) represents a secondary technology measure that is required to determine the grid state in terms of node voltages and equipment loading in real time. Hence, DGA itself is not a planning measure. Nevertheless, it is essential to be parametrised as it serves as a base technology for implementing other innovative technologies, such as LM.

With the implementation of DGA, the determined grid state is then utilised to regulate the grid components accordingly. Depending on the targeted usage, the application of DGA can range from decreasing or eliminating grid limit violations by regulating load or generation using LM or generation management [112], [113].

Method of operation

DGA consists of a remote terminal unit (RTU), measurement sensor(s), actuator(s) and a communication medium connecting the components [112]. The RTU receives, collects, and processes the data measured by the measurement sensor(s) installed in the grid to determine the grid state. Based on the grid state, the RTU generates commands to the actuators to influence the grid state according to a predefined set of rules. The measurement sensors are used to measure the node voltage at the grid nodes where the measurement sensors are installed. Additionally, the measurement sensors can measure the current flow through certain equipment. The actuators represent the active control in the grid, which differs depending on the targeted application and the mode of control. The data transfer between the components occurs through a communication medium, to which they are all connected. This set of components is summarised with the term: Measurement, Information, and Communication Technology (MICT).

In the context of applying DGA, it is assumed that the new technologies CPs, HPs and PV systems already include in-built actuators that enable load regulation. Furthermore, the communication medium is chosen to be done over the LTE network [114], [115], which already exists in the investigated urban grid areas. The incurring costs for SIM cards required for communication are neglected in comparison to the grid reinforcement costs. Moreover, the measurement sensors necessary for determining the grid state do not need to be installed at each grid node. According to [116], the grid state can be determined by using measurement sensors installed at a few selected grid nodes and by applying intelligent calculation techniques.

Modelling and application

Since DGA represents a base technology for further technologies, the modelling of the specific technologies is explained in the upcoming sections.

Specifics of the technology

One challenge facing DGA is the discrepancy between the actual node voltages and flowing currents with the measured node voltages and flowing currents. A non-accurate calibration of the measurement sensors may deliver unreal readings, which leads to a false grid state estimation. Therefore, the components of DGA must be regularly tested to ensure their accuracy in measurement and signal transmission. Besides the physical components, the software running on the RTU needs to be maintained and checked at regular intervals.

It must be considered that, in case DGA fails, the grid state estimation ceases and the active grid control can no longer be performed, which may lead to a non-standard-compliant grid operation. In this case, it is recommended to pre-set fall-back regulation values parametrised by the DSO for the individual actuators in the grid to ensure a safe grid operation. [117]

3.9.2 Load Management

LM refers to the technology that regulates controllable loads depending on the current grid state. It is sometimes referred to as "demand side management" which is the "process that is intended to influence the quantity or patterns of use of electric energy consumed by end-use customers" [118]. Several concepts for demand side management have been introduced in the literature with one of the first concepts introduced in 1985 [119]. The concept proposed at that time focused on regulating the conventional loads for the benefit of electric utilities.

With a focus on strategic grid planning with the consideration of EVs and HPs, the proposed LM concept operates by regulating CPs and HPs to maintain the grid limits in terms of node voltage and equipment loading. These new loads offer a degree of flexibility, which can be utilised according to the grid state.

Method of operation

The mode of operation of LM is the regulation of the new loads' active power so that the grid state remains within the allowed grid operation limits. Generally, the maximum load regulation (complete shutdown) offers the technically best solution, since it reduces the grid loads to the minimum. However, the maximum regulation corresponds to a maximum loss of comfort for the end consumers. Therefore, an appropriate load regulation, that balances the loss of comfort of the consumers and the remedy of grid limit violations, needs to be found for LM. Furthermore, the proposed LM does not regulate the new loads according to the energy market.

Firstly, LM has to be both grid-oriented and consumer-oriented. Referring to [45], charging stations[12] with a total rated apparent power $S_r > 12$ kVA require the approval of the DSO to be connected. Whereas, charging stations with a total rated apparent power $S_r \leq 12$ kVA simply require registration at the DSO.

[12] It can contain a single charging point with $P_{CP} = 22$ kW or several charging points.

According to this rule, a DSO can approve CPs with $S_r > 12$ kVA with the condition of charging power regulation. This differentiation between CPs in terms of charging power is relevant, especially for the widely spread uncoordinated integration of prCPs. As for HPs, it is assumed that they can be shut down during specific turn-off periods following the DSO's specific turn-off time windows.

Depending on the above-mentioned reasons, three LM variants are proposed. Table 3.6 shows the regulated load type for each of the LM variants. Within LM Variant 1 (LM-V1), the HPs and the prCPs are regulated, whereas LM Variant 2 (LM-V2) regulates only the prCPs. In contrast, LM Variant 3 (LM-V3) operates by regulating the puCPs and the ufCPs. The ufCPs are considered a part of the puCPs and are regulated accordingly. The three LM variants represent the influence of regulating each load on the final grid planning. [120]

Table 3.6: Overview of the regulated load for each of the three load management variants ("✓": regulated, "-": not regulated) [120]

Regulated Load	Load management		
	Variant 1	Variant 2	Variant 3
Heat pumps	✓	-	-
Private charging points	✓	✓	-
Public charging points	-	-	✓
Ultra-fast charging points	-	-	✓

It is to be noted that a further LM variant which regulates the HPs, prCPs, puCPs, and the ufCPs is not executed since such a variant merely represents the current is-case of the MV grids. Each of the LM variants can regulate the load up to a predefined boundary. Since CPs (whether they are prCPs or puCPs) can have a charging power of $P_{CP} = 3.7$ kW through a 1-phase alternating current outlet, the minimum charging power is set according to $P_{CP} = 3.7$ kW. Thus, with the maximum regulation of LM, the CPs are not completely shut down and the end consumers can still charge their EVs at the corresponding CP with less power. Generally, the regulation of the CPs is performed proportional to their charging power so that no discrimination occurs in favour of CPs of higher or lower charging powers. The regulation starts with 1 % of the charging power P_{CP} and increases so that at the maximum regulation of the CPs, the users can still charge with $P_{CP} = 3.7$ kW. As for HPs, the LM can shut down the regulated HP(s) completely at a predefined time slot. This corresponds to the shut-off periods already set by several DSOs.

Figure 3.7 (p. 55) shows the proposed method of operation of LM. The operation starts by running a load flow calculation to determine whether there is a grid limit violation. In case of a grid limit violation, the LM selects the new load(s) to be regulated based on the chosen LM variant. If the regulating boundary of the selected new load(s) is reached, no further regulation can be executed.

If the regulating boundary is not yet reached, the LM regulates the selected loads. The whole process is repeated iteratively until either the grid limit violation is remedied or until the selected load(s) have reached their maximum regulating boundary. In the case of LM-V1, the LM starts by turning off the HPs, as it corresponds to the minimum loss in comfort for the end user. If grid limit violations persist after turning off the HPs, the LM regulates the power of the prCPs. As for LM-V2, the charging power of the prCPs is regulated proportionally until the grid limit violations are remedied or the minimum charging power of $P_{CP} = 3.7$ kW is reached. LM-V3 operates similar to LM-V2 with the difference that LM-V3 regulates the puCPs instead of the prCPs.

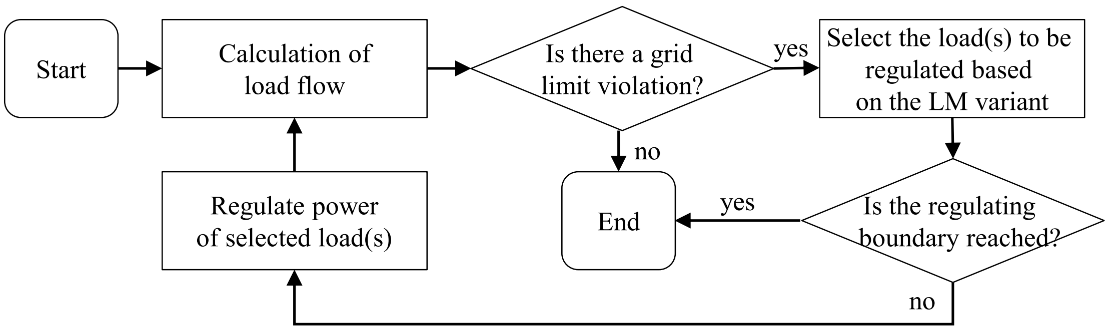

Figure 3.7: Method of operation of load management in the grid planning based on [120]

Modelling and application

Since LM regulates the new loads connected in the downstream LV grids and the ufCPs connected in the MV level, the modelling and application of LM are considered to be a cross-voltage level technology.

In order to remedy grid limit violations in the MV grid, the new loads at the LV level are regulated, even though they may not need to be regulated from the perspective of the downstream LV grids. Furthermore, by applying load regulation from the feeder perspective, the new loads at the LV grids connected to feeders with grid limit violations are controlled as opposed to the new loads at the LV grids connected to another feeder(s) without grid limit violations. Hence, a complete non-discriminating regulation of the loads is nearly unachievable without regulating non-relevant new loads.

Figure 3.8 (p. 56) shows the steps for the installation of the DGA components to apply LM in the MV grid. First, a differentiation is done depending on whether the primary substation transformers are overloaded at the peak load operating point for a specific scenario and investigation year. In case the primary substation transformer is overloaded, and the overloading is preventable using LM, the components for LM are installed in the complete grid area at all the required secondary substations. In case the primary substation transformer is not overloaded, or the transformer overload cannot be prevented with LM, the loading of the feeders is checked. Consequently, the components for LM are installed selectively at the overloaded feeders in the MV grid. This aims to save cost for the installation of the required components for applying LM.

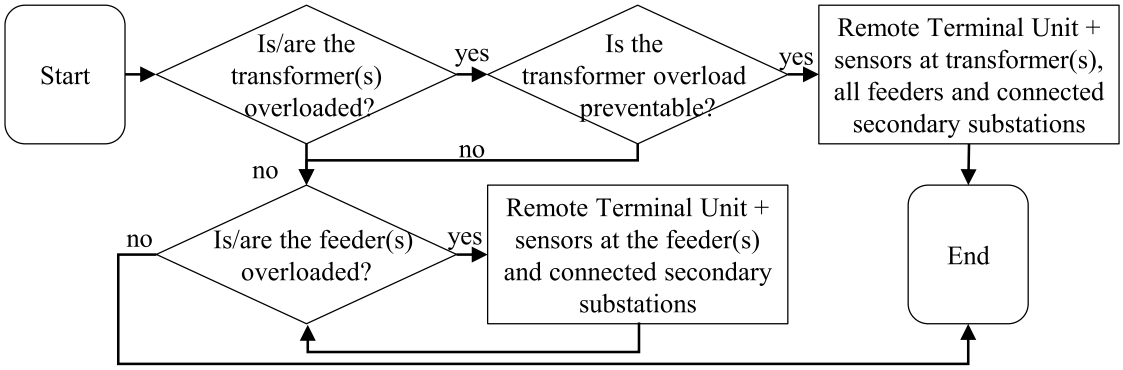

Figure 3.8: Steps for the installation of the components of the decentralised automation system for applying load management based on [120] (transformer = primary substation transformer)

According to the steps for the installation, the components for the LM can be installed either over the complete MV grid area or for a specific feeder. The MICT can then be installed at specific grid nodes so that the LM can determine the grid state sufficiently accurately enough to regulate the new loads correspondingly. To investigate the influence of the installation of MICT costs in comparison to the costs of conventional planning, six LM layouts are assumed. The LM layouts differ in the required extent of the installation of MICT into the MV grids. Table 3.7 (p. 57) lists the proposed LM layouts and Figure 3.9 (p. 57) shows the LM layouts graphically.

The layouts start with the widest range of installation of MICT, namely, (MV + LV). In this layout, it is assumed that the MICT needs to be installed into the MV grid and all the downstream LV grids since neither of the voltage levels is equipped with MICT. This corresponds to the installation of two LV sensors at each of the secondary substations to be controlled in addition to the measurement sensor for the MV feeder and the RTU. With the two LV sensors at the LV side of the secondary substations, the loading, and the voltage for up to eight feeders can be measured in addition to the MV/LV transformer loading.

The second layout (MV + 50 % LV) assumes that the downstream LV grids are already equipped with half of their required MICT, namely, the LV sensors measuring the current on the LV side of the MV/LV transformers at the secondary substations. Hence, a single MV sensor is required per secondary substation to measure the MV/LV transformer loading in addition to the measurement sensor for the MV feeder and the RTU.

The third layout (MV) assumes that the LV level is already equipped with MICT and, in this case, few MV sensors are installed at selected MV grid nodes in addition to the measurement sensor for the MV feeder and the RTU. The fourth layout (Red. MV) assumes that the MV level is partially equipped with MICT. Therefore, a single MV sensor is required at a selected secondary substation per feeder in addition to the measurement sensor for the MV feeder and the RTU.

The fifth layout (B) supposes that the MV grid is already equipped with MICT and that only the RTU is required to operate the LM. The sixth layout (0) assumes that LM is already installed completely and no further components are needed.

Table 3.7: Overview of the six load management layouts [96]

Load management layout	Specifications
Total costs (MV + LV)	MICT is needed in the MV grid as well as all the LV grids
Half the costs (MV + 50 % LV)	MICT is needed in the MV grid and half of the LV grids as the other half of the LV grids is already equipped with MICT.
MV costs (MV)	MICT is needed in the MV grid, whereas the LV grids are already equipped with MICT
Reduced MV costs (Red. MV)	MICT is needed in a reduced coverage in the MV grid, since it is already partially equipped with MICT.
Base costs (B)	A remote terminal unit is needed to operate LM, since MICT is fully constructed in the MV grid.
No costs (0)	All the LM components are already constructed.

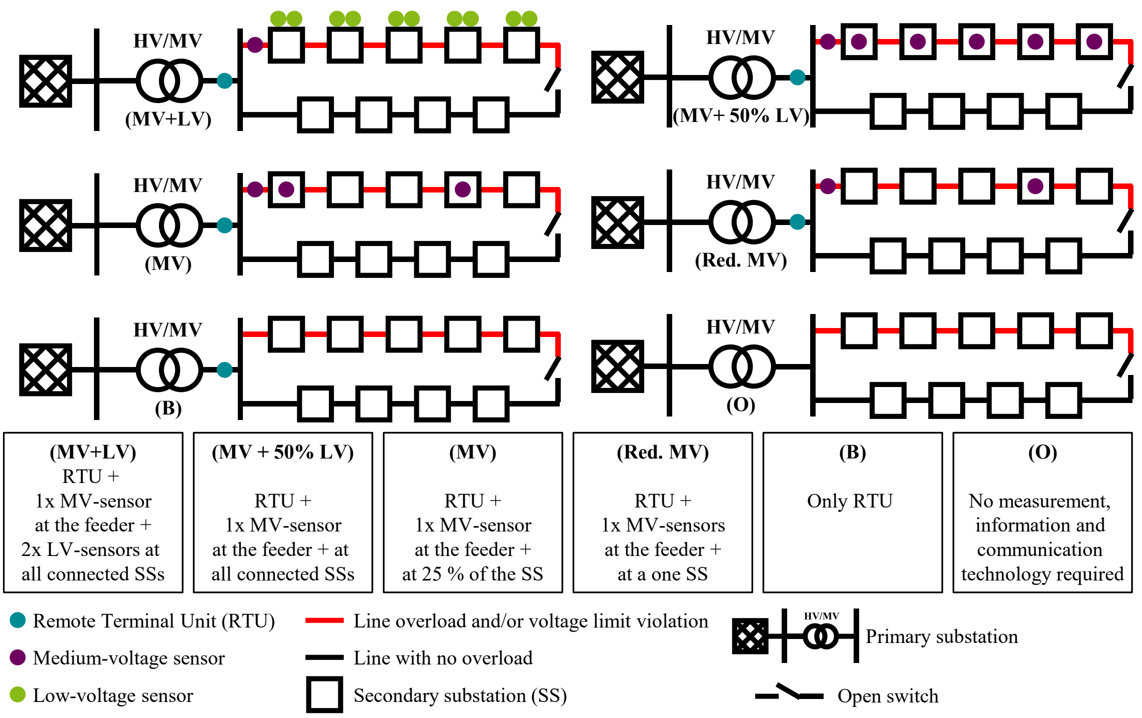

Figure 3.9: Illustration of the six load management layouts for one medium-voltage ring [96]

Specifics of the technology

Referring to the *VDE-AR-N 4110* [72], the charging stations with $S_r \geq 12$ kVA must be controllable according to the regulations of the DSO. A controllable charging station should be able to receive an external signal for controlling the charging process. In this case, the DSO can send signals to the charging stations to regulate their charging power. The regulation of the HPs, on the other hand, is already executed by several DSOs according to differing regulating strategies. Since LM operates by installing DGA, the specifics of DGA mentioned in section 3.9.1 should be considered.

3.9.3 Energy Storage

ES refers to a device that can intake (charge) electrical energy from the grid at a given point in time and feed in (discharge) the stored energy into the grid at a later point in time [121]. The storage of electrical energy occurs through conversion into chemical energy. Henceforth, the ES can be loosely understood as battery storage.

Method of operation

The charging and discharging of the ES can be controlled by different business models. One of the business models is the market-oriented one. In the market-oriented business model, the charging and discharging of the ES are controlled by energy price signals according to the energy market. In this case, an economic profit can be achieved by charging and discharging the ES. A second business model is the grid-oriented one. In the grid-oriented business model, the ES is controlled according to the grid state. In the off-peak time windows, the ES charges by withdrawing energy from the grid so that during the peak time windows, the ES discharges this energy back into the grid. By charging and discharging the ES in the grid-oriented business model, grid limit violations can be avoided completely or at least reduced. Alternatively, the ES can be used in case of an island operation within a customer installation. However, this use case is not investigated.

With the target of strategic grid planning, only the grid-oriented operation is considered as the market-oriented operation can–in some cases–lead to further grid limit violations.

Modelling and application

The two operating modes of the ES (charging and discharging) are specified in [45]. From the grid perspective, the ES behaves as a load in the grid and draws power from the grid while charging. In the discharging mode, the ES behaves as a DG and injects power into the grid.

The modelled ES is grid-oriented, so it aims to remedy grid limit violations. With DGA determining the grid state, the ES switches to one of the two operating modes. When the grid state is unstrained (off-peak time), the ES charges according to the available grid reserve in terms of node voltage and equipment loading. At the peak load operating point, the ES discharges energy to restore the node voltage within the set voltage limit and to reduce the feeders loading at which the ES is installed.

Based on the critical nodes and equipment in the grid, the ES is positioned. In case the ES is required to remedy voltage limit violations, it is recommended to position the ES at the end of long feeders to substitute the maximum voltage drop of the feeder. When the ES is applied to remedy equipment overloads, it is recommended to position the ES close to the overloaded equipment. This can be done based on the results of the load flow calculation.

Dimensioning the ES depends on the required energy during the peak load time in comparison to the available energy during the off-peak time. An accurate dimensioning of the ES needs a time-series load flow calculation to determine the available and the required energy during off-peak and peak times, respectively. Since the investigated new loads are still not widely spread in the grids, the currently recorded time series for these loads are not reliable for a strategic long-term grid planning. Hence, the ES is modelled and dimensioned without a time-series calculation. The peak power of the ES equals the required active power to remedy the grid limit violations occurring at a specific feeder in the peak load operating point. With the assumption that the peak load operating point lasts for a maximum of two hours, the ES is dimensioned to supply its peak power for two hours continuously.

Specifics of the technology

Unlike the previous innovative technologies, an optimal position of the ES may not always be practically feasible due to space constrictions at the grid node. Hence, further positioning restrictions for installing the ES must be considered on a grid-to-grid basis. Furthermore, the performance of the ES strongly depends on the surrounding temperature. Extreme temperatures can drastically decrease the performance rate of ES. Therefore, it must be installed in cool and dry areas. An advantage of the ES, in contrast to conventional measures, is that the rated power and the capacity of the ES can be flexibly increased by adding further modules.

Applying each of the above-mentioned planning measures and technologies to a specific MV grid for a specific development scenario and HP model results in a PA. An overview of the generated PAs per MV grid is shown in Figure 3.10. In the first step, the MV grid is differentiated between the two scenarios and the three HP models (see Table 3.3), thus resulting in six different development paths per MV grid. Consequently, the emerging grid limit violations are remedied by five different planning measures and technologies, thus generating 30 different PAs per MV grid. To investigate the fitness of the applied planning measures and technologies, the PAs are assessed economically as well as technically using a uniform assessment model.

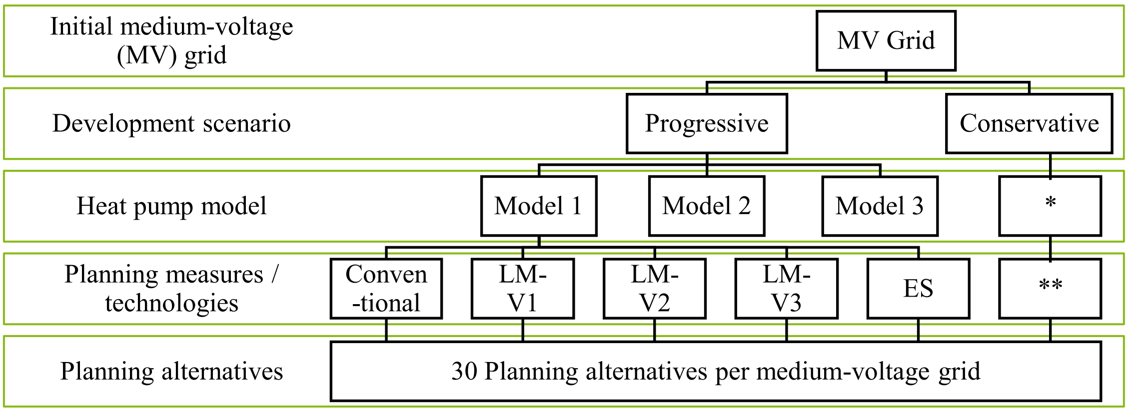

Figure 3.10: An overview of the generated planning alternatives per medium-voltage grid according to the development scenario, the heat pump model and the applied planning measures and technologies (LM = Load Management, ES = Energy Storage, * = HP models 1, 2 and 3, ** = Conventional, LM-V1, LM-V2, LM-V3 and ES)

3.10 Assessment of the Planning Alternatives[13]

The assessment model analyses the changes done to the final grid model in a specific future scenario in comparison to the recent grid model. The considered changes are the planning measures executed to overcome the grid violations resulting from integrating the elements of the energy transition into the grid. All other measures (such as maintenance and renewal of the equipment) are not considered in the assessment. Hence, only newly added equipment (i.e. conventional planning measures or innovative planning technologies) is considered in the techno-economical assessment model.

Figure 3.11 shows the composition of the developed assessment model, dividing it into a primary and an alternative assessment model. The primary assessment model relies on the cost of measures as a single assessment criterion to determine the quality of the PA. Hence, the primary assessment model is purely economic.

In contrast, the alternative assessment model considers four additional assessment criteria in determining the quality of the PA, namely, grid losses, frequency of failure, voltage reserve, and effort of construction. The wide range of considered assessment criteria makes the alternative assessment model a techno-economical model covering both economical and technical aspects of the grid planning.

Since the DSOs base their long-term strategies on a purely economic base, the primary assessment model is considered for the deduction of the PGs. This goes along with the decision-making strategies of DSOs when it comes to grid reinforcement. Since the assessment criteria considered in the alternative assessment model are not considered by all DSOs, its results are introduced as an additional analysis for assessing the PAs. The results of the alternative assessment model are shown in section 5.4.2 (p. 118).

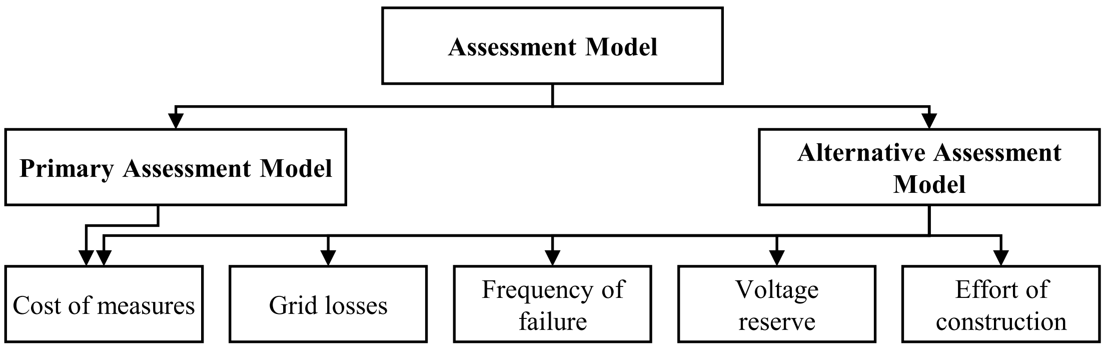

Figure 3.11: The composition of the assessment model with the corresponding assessment criteria

[13] The method explained in this section has already been published in [40] and [122].

3.10.1 Primary Assessment Model

The deduction of the PGs is based on the primary assessment model "an economic assessment model" to achieve a cost-optimised strategic grid planning. Therefore, the primary assessment model considers solely the cost of measures as the single assessing criterion for decision-making.

1. **Cost of measures**

The cost of measures represents the costs (investment and operating) that the DSO needs to install and maintain new equipment in order to remedy or avoid grid limit violations.

The two dominant methods for calculating the cost of measures are net present value and equivalent annual cost. Both methods implement a discounted cash flow criterion of investment evaluation. The equivalent annual cost method represents the annual amounts "annuity" to be invested yearly while the net present value discounts all future investments into the present. The equivalent annual cost method results in amounts that are more comprehensible to a decision-maker since numerous organisations report their activities on an annual economical basis. On the other hand, the net present value yields present investment sums that are of an incomparable magnitude to the actual investments and may be misleading. [123]

Even though these two methods calculate the total investments differently, they lead to the same final decision while comparing investment alternatives. The net present value method is, however, more suitable for finding a common point of reference (present day) in comparing different investment strategies (in this case PAs) over an extended period of time (until the year 2050) [124]. Therefore, the net present value method is used for calculating the cost of measures of the different PAs. The investments considered in the cost calculation using the net present value method are the construction costs for the newly installed equipment and the yearly operational costs for maintaining this newly installed equipment and its power losses. The costs for renewing, running and maintaining the already existing equipment are not considered in the investments.

Figure 3.12 (p. 62) shows the applied cost calculation method. The start year is set to the year 2021[14]. The investment years (2025, 2035 and 2045) are chosen to be in the middle between each of the investigation years and represent the year in which the equipment is installed. The cost of measures at each of the investment years is discounted to the start year 2021. In addition, yearly operational costs for the newly installed equipment are calculated until the final investigation year 2050 and discounted to the start year 2021. By the end of the investigated period of time, the residual value of the newly installed equipment is considered as a fictitious income according to the equipment's service life. This ensures that the remaining service life of the installed equipment is considered in the cost calculation for better comparability of the PAs. The costs per measure, their operational costs, and their service life are listed in section 8.2 (Table 8.1, p. 153).

[14] The cost calculation is performed for the year 2021.

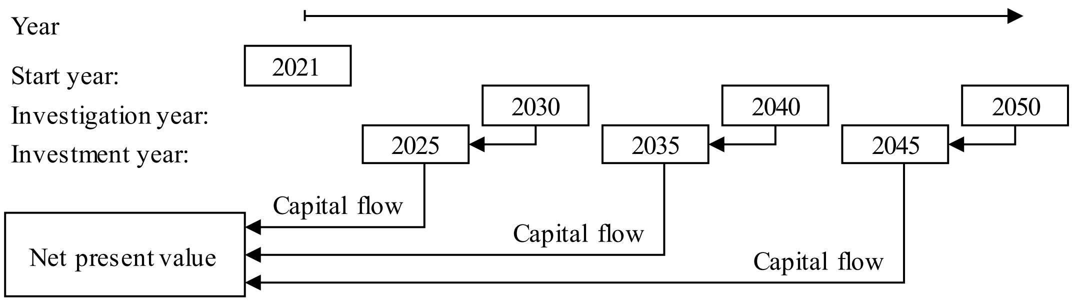

Figure 3.12: Cost calculation method based on the net present value method [40]

The cost calculation method applies an interest rate based on the regulatory-weighted interest rate determined by the German Federal Network Agency. [125] explains how the investment costs in the grid infrastructure are calculated, where the equity ratio is assumed at 40 % and the interest bearing-debt is assumed at 60 %. [126] investigates the development of interest rates and proposes the use of averaging in rate regulation. Based on the two previous publications, an average interest rate value of $r = 5$ % for the cost calculation is assumed. As for the lifetime of the equipment, the calculated service life of the equipment is assumed and not the actual technical lifetime.

3.10.2 Alternative Assessment Model

Although the cost evaluation is proven practical in determining the most suitable PA, it neglects the advantages offered by innovative technologies in terms of flexibility and grid usability. Hence, in addition to the purely economic consideration, other aspects, such as grid losses, can be valuable assessment criteria for determining the most suitable PA. Therefore, the alternative assessment model proposes four further assessment criteria for determining the fitness of the PAs. The results of applying the alternative assessment model are shown in section 5.4.2 (p. 118).

Assessment Criteria:

2. **Grid losses**

The grid losses represent a technical aspect of the grid that evaluates the grid efficiency and is, therefore, important for the DSOs. The grid losses represent ongoing losses in the operation costs, which depend not only on the equipment of the grid but also on their loading. This assessment criterion evaluates the final grid state, including the already existing equipment and loads. Based on a load flow analysis of the target year 2050 for the peak load operating point, the grid losses are calculated per PA. The load flow analysis yields the annual energy losses in megawatt hours (MWh), which is then used in assessing each PA. It must be noted that this is an approximation of the annual energy losses in the grid. Whereas, an accurate calculation of the grid losses requires a time series calculation. Using the electric energy costs, the grid losses can be calculated in monetary terms and can be considered along with the annual equipment operating costs. However, to avoid the complexity of forecasting future energy prices, the grid losses are assessed in MWh. Obviously, the fitness of a PA is inversely proportional to the grid losses.

3. Frequency of failure

Similar to the previous assessment criterion, the frequency of failure is a technical aspect of the grid state. As a simplified grid reliability analysis, the frequency of failure evaluates how often a DSO needs to perform measures to keep the grid running. Hence, it represents an estimate of the operation and maintenance effort performed by the DSO. There is a differentiation between the frequency of supply interruption and the frequency of failure, whereas not every equipment failure leads to an interruption of the supply. Nevertheless, maintenance works need to be performed for each equipment failure in the grid.

The frequency of failure F considers not only the newly installed equipment over the investigated years, but rather all equipment in the grid. It is calculated by multiplying the total quantity n_{k} (in meters or the number of units) of a certain equipment type k in the grid with the failure rate of this equipment type λ_{k} in a year. Since the independent single failure is the most comment failure, the corresponding rates of failure are taken from [127]. The rates of failure of each equipment type are multiplied by the quantity of this certain equipment type in the grid. The frequency of failure of a MV grid is then calculated as the sum of the failure rate of each equipment in the grid multiplied by its quantity for the final grid state in the year 2050. This is executed according to equation (3.29). Clearly, the fitness of a PA is inversely proportional to the calculated frequency of failure.

$$F = \sum n_{\mathrm{k}} \cdot \lambda_{\mathrm{k}} \tag{3.29}$$

The applied rates of failure are listed in the appendix (section 8.5, p. 156).

4. Voltage reserve

A further technical aspect to assess the PAs is the voltage profile. The proposed assessment criterion, namely, voltage reserve indicates the robustness of a PA against slow voltage changes without the occurrence of a voltage limit violation. The voltage reserve is particularly an important assessment criterion. Since the MV and the LV voltage levels are directly coupled, a change in the voltage profile in a voltage level can result in a voltage level violation in the downstream LV grids. Hence, the voltage reserve represents an operational safety margin for the grid.

The voltage reserve V_{res} is evaluated by calculating the maximum voltage change in the MV grid between the nominal voltage (the MV busbar of the HV/MV primary substation busbar) V_{n} and the minimum node voltage level $V_{\mathrm{N,min}}$ in the MV grid. This is executed according to equation (3.30). The fitness of a PA is directly proportional to the voltage reserve.

$$V_{\mathrm{res}} = V_{\mathrm{n}} - V_{\mathrm{N,min}} \tag{3.30}$$

5. Effort of construction

Unlike the three previous assessment criteria, the effort of construction does not assess a technical aspect of the grid, but rather a practical aspect of grid reinforcement. The effort of construction criterion represents the construction work done by the DSO to carry out the measures of a certain PA. This criterion increases in importance with the introduction of innovative planning technologies (e.g., LM) that remedy grid violations without major measures like replacing long lines or renewing substations.

With the cities becoming more crowded, applying measures, such as laying or replacing lines, results in noise pollution due to digging and especially the inconvenience of closing the roads. As a simplification, the effort of construction is evaluated by the length of the dug line route required to realise a certain PA. The fitness of a PA is inversely proportional to the effort of construction.

With the help of the calculated values per assessment criterion, the PAs can then be compared to assess and rank them according to their fitness.

Scoring System:

Since each of the assessment criteria results in a different unit of measurement (e.g., grid losses in MWh, whereas the cost of measures in € and the effort of construction in km), a unified scoring base is necessary to compare the fitness of each PA by combining the assessment criteria. Therefore, the upcoming scoring system is developed to maintain a unified comparison of the PAs.

After calculating the values of the assessment criteria for all investigated PAs, a value range is set per assessment criterion. This range spans between the best and the worst value of the specific assessment criterion over all PAs. For instance, the assessment criterion "grid losses" would have the best value corresponding to zero losses and the worst value corresponding to the maximum grid losses over all PAs. The identified range is then used as baselining to rank the PAs per assessment criterion according to their score. The score assigns a rank per PA for each of the assessment criteria and is calculated according to equation (3.31).

Where AC_{a} is a certain assessment criterion a, PA_{b} is a certain planning alternative b and TS is the top score.

$$Score_{\mathrm{AC_a,PA_b}} = TS - \left(\frac{Value_{AC_{(a)},PA_{(b)}}}{Worst\ value\ of\ AC_{(a)} over\ all\ planning\ alternatives} \cdot TS\right) \tag{3.31}$$

The top score is an assumed value of the highest rank to be assigned to a PA for a specific assessment criterion. The top score can be arbitrarily chosen. However, it is recommended to be set equal to the number of PAs. By applying equation (3.19) per PA for each of the assessment criteria, each PA gets a rank for each of the assessment criteria.

For example, the PA "conventional planning" can have the best rank in cost of measures, the third rank in "grid losses", the worst rank in "frequency of failure", the second rank in "voltage reserve" and the worst rank in "effort of construction". According to the ranks per assessment criterion, the PAs can be arranged in order.

The combination of the assessment criteria into a single indicator, on which the fitness of a certain PA can be determined, is desirable. This combination can be achieved by adding the scores of the assessment criteria and weighing each of the criteria according to the DSO's preference. Accordingly, assessment strategies for the sum of the scores are developed.

Assessment strategies:

With the scoring system, the PAs can be compared per assessment criterion. However, it can also be beneficial to assess the PAs by referring to not only a single assessment criterion, but rather a weighted combination of the assessment criteria. This evaluation can be realised by introducing assessment strategies. The proposed assessment strategies consider all the assessment criteria with different weightings according to the DSO's preferences. Furthermore, they are expandable and interchangeable, in case a different assessment strategy is required.

1. **Equal weighting**

This assessment strategy relies on the assumption that all assessment criteria are equally important for determining the PA. Hence, all assessment criteria are equally weighted.

2. **Economically oriented**

This assessment strategy lays the focus on the economic aspect of the PA but not solely on it. Thus, the assessment criterion "Cost of measures" is weighed the most, whereas the remaining assessment criteria are given an equally smaller weighting.

3. **Grid resilience**

This assessment strategy considers the stability of the PA to be most important for the DSO. Hence, the assessment criteria "Voltage reserve" and "Frequency of failure" are given the highest weightings, since they represent the stability of the grid against voltage disturbances and equipment failures.

4. **Technically oriented**

This assessment strategy assumes that the technical aspects of the PA, namely, "Grid losses", "Voltage reserve" and "Frequency of failure" are the decisive criteria for a PA from the point of view of the DSO. Therefore, these three mentioned assessment criteria are weighted more in calculating the final score of the PA.

5. Conservation of resources

This assessment strategy focuses on preserving the resources used not only for grid planning but also for operation. The resources used in the grid planning are represented by the assessment criterion "Effort of construction", whereas the resources used in the grid operation are represented by the assessment criterion "Grid losses". Hence, these two aforementioned assessment criteria are weighted more in calculating the final score of the PA.

A summary of the assessment strategies and the specific weighting values is given in Table 3.8 (p. 66). It must be noted that the specific weighting values are assumptions performed in this work.

Table 3.8: An overview of the assessment strategies and their specific weighting values based on [122]

Assessment Criterion	Assessment strategy				
	Equal weighting	Economi-cally oriented	Grid resilience	Technically oriented	Conserva-tion of resources
Cost of measures	20 %	60 %	10 %	5 %	10 %
Grid losses	20 %	10 %	10 %	30 %	35 %
Frequency of failure	20 %	10 %	35 %	30 %	10 %
Voltage reserve	20 %	10 %	35 %	30 %	10 %
Effort of construction	20 %	10 %	10 %	5 %	35 %

Even though each assessment strategy lays the most weight on a single assessment criterion or several assessment criteria, the remaining assessment criteria are not weighted with zero. This is done under the assumption that even when a certain assessment criterion is not in focus for the PA, all assessment criteria should be considered for determining the fitness of a PA. For each PA, the final score is then calculated based on the scoring value per assessment criterion multiplied by the specific weighting value depending on the assessment strategy. The final score is calculated according to equation (3.32). Each of the PAs gets a final score in relation to each of the five assessment strategies. Where $W_{\mathrm{Ac}_{(\mathrm{a})}}$ is the weighting of an assessment criterion a.

$$Final\ Score_{\mathrm{PA_b}} = \sum\nolimits_{a} \left(W_{\mathrm{AC}_{(\mathrm{a})}} \cdot Score_{\mathrm{AC_a},\mathrm{PA_b}}\right) \tag{3.32}$$

The results of applying the alternative assessment model are presented and discussed in section 5.4.2 (p. 118) in the context of a sensitivity analysis for the PGs. With the development of the primary and the alternative assessment model, the methodology of the strategic grid planning is concluded. The methodology is then applied to the MV grids to generate the results needed as a basis for deducing the PGs.

4 Application of the Strategic Grid Planning

Continuing the investigation for the influence of the elements of the energy transition, the developed methodology of the strategic grid planning is then applied to MV grids. Starting from this chapter, the term "MV grid" is used to refer exclusively to an urban MV grid, as this dissertation focuses on deducing PGs for urban MV grids.

Firstly, the representative MV grids are determined as the base model for applying the methodology of the strategic grid planning. Secondly, the chapter presents planning examples for three MV grids. Following the planning examples, the impact of DG on the investigated MV grids is analysed. Finally, a technical and economic assessment of the PAs is presented and discussed.

4.1 Analysis of Urban Medium-Voltage Grid Structures[15]

The non-automated grid planning of all MV grids operated by a DSO can be a complex and time-consuming assignment. Depending on the similarities between the MV grids, an approach is developed which is based on selecting a few MV grids for the grid planning. Each selected MV grid needs to represent several other MV grids of similar characteristics. Hence, the generated results can then be projected and applied to other MV grids.

Firstly, the available database of the MV grids is examined. By statistically analysing the available database of the MV grids, the general characteristics of the MV grids are concluded. These characteristics are then input into a clustering algorithm, which differentiates the MV grids into different clusters. Based on the resulting clusters, representative MV grids are chosen for the analysis.

4.1.1 Characteristics of Urban Medium-Voltage Grids

To determine representative MV grids, the MV grid structure data from six major German DSOs are gathered into a MV grid database. The DSOs operate in German cities of varying size and density ranging from metropolitan cities with more than three million residents to large cities with hundreds of thousands of residents and extending to cities with just over a hundred thousand residents. Hence, a statistical analysis of the collected MV grid structure is executed to maintain a uniform MV grid database independent of the specific differences between the individual DSOs. To correctly define the boundaries of each MV grid, it is set that all elements supplied from a single primary substation are defined as a MV grid.

[15] The method and the results presented in this section have already been published in [40] and [128].

Subsequently, the structural data needs to be filtered from incomplete and non-uniform data entries that may distort the MV grid database. Thus, a total of 146 urban MV grids for the voltage levels V_n = 10 kV and V_n = 20 kV remain in the pool of the statistical analysis. For each MV grid, the parameters: line length, number of secondary substations, the number of building connections and the number of metering points remain available in the MV grid database. Hence, these parameters are analysed using a statistical analysis. As a result, the frequency of distribution of each of the parameters is determined as shown in Figure 4.1.

In the top left corner of the figure, the line length in km per MV grid is displayed. That the majority of MV grids have a line length of around l = 30 km to l = 80 km. As for the number of secondary substations per MV grid displayed in the top right corner of the figure, the majority of MV grids have around 30 to 70 secondary substations per MV grid. In the bottom left corner and the bottom right corner of the figure, the number of building connections and the number of metering points per MV are shown respectively. The majority of MV grids have around 1,000 to 4,000 building connections per MV grid. As for the metering points, the majority of MV grids supply around 6,000 to 21,000 metering points per MV grid.

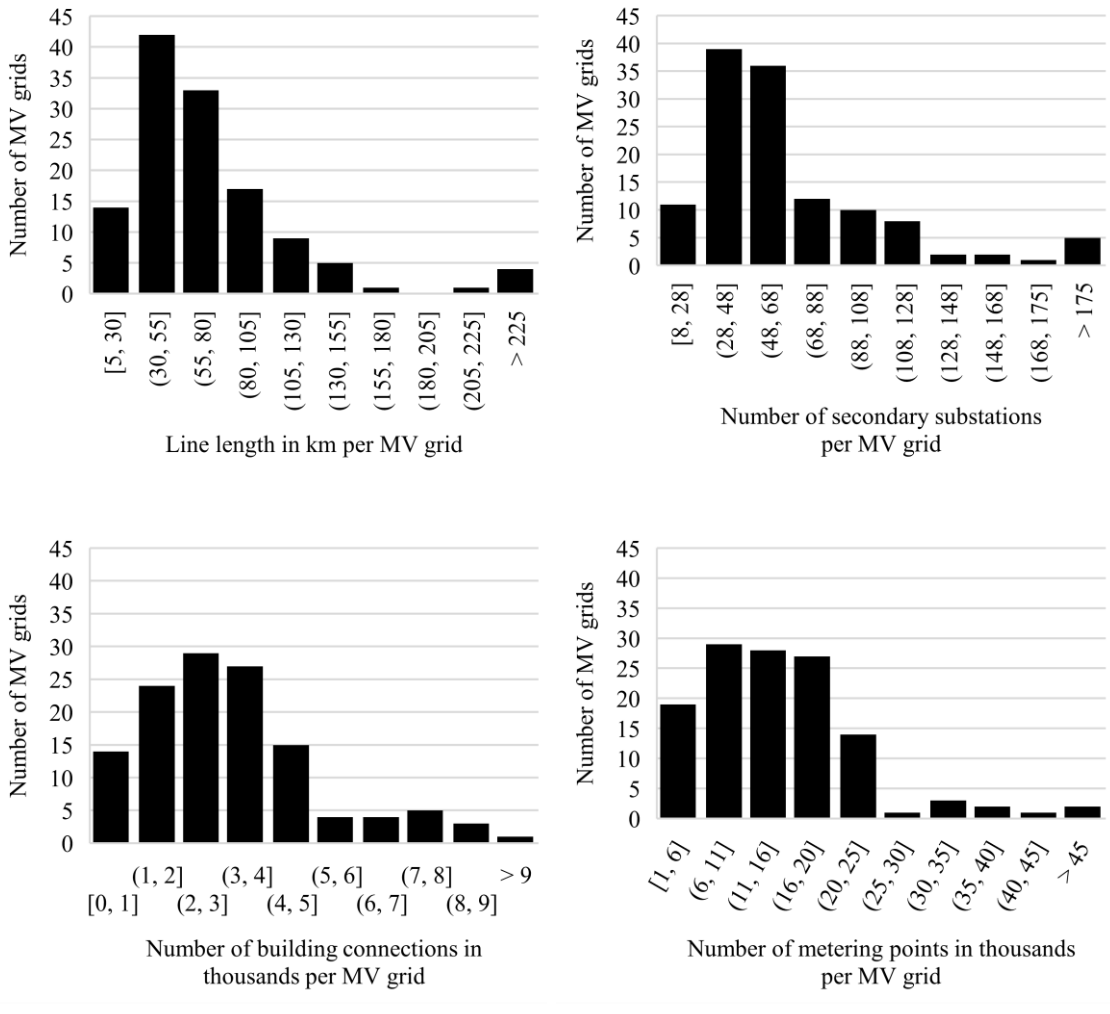

Figure 4.1: Overview of the grid parameters in the medium-voltage grid database [40] (MV = medium-voltage)

4.1.2 Clustering of Urban Medium-Voltage Grids

Clustering algorithms have already been introduced in literature (e.g., [129], [130]) as a tool for analysing big datasets. Generally, the clustering algorithms can be used to select representative MV grids as explained in [131]. According to the desired number of clusters and the clustering parameters, the clustering algorithm attributes each of the entries in the input database to a cluster, thus generating the clusters. The database is divided in such a way that the entries within the cluster are as similar as possible and yet different to the other clusters. The cluster centre is the mathematically calculated centre of cluster parameters of all the entries attributed to this cluster.

Based on the survey of the clustering algorithms presented in [129], [130], the partitioning algorithm, namely, the *k*-means clustering algorithm [132], is chosen for clustering the MV grid database. The low complexity, the fast computational time and the scalability for large databases of the *k*-means algorithm make it suitable for the task at hand.

The optimum number of clusters for formulating representative MV grids is investigated in [133]. The study determines the optimum number of clusters by analysing several clustering criteria such as the Calinski-Harabasz criterion and the Silhouette criterion. Finally, it determines the optimum number of clusters for the analysed MV grids to be six clusters. Since the paper applies the *k*-means to a dataset of MV grids, which corresponds to this work, the number of clusters is set to six.

Building on the grid parameters in the MV grid database, the clustering parameters are determined. The first clustering parameter combines the number of metering points with the number of secondary substations by calculating the average number of metering points per secondary substation which corresponds to the load density in the MV grid. The representation of the load density correlates to the expected integration of new loads in the MV grid since the new loads are expected mainly in the downstream LV grids. The second clustering parameter associates the number of secondary substations in a MV grid with its line length by calculating an average number of secondary substations per line length, which corresponds to the connection density. The connection density clustering parameter correlates with the expected loading in the MV grid, as the loading of the MV grid lines is expected to increase with an increasing connection density. Besides the grid characteristics, that are deducible from the two clustering parameters, these clustering parameters are chosen according to the available data for all the grids in the MV grid database. Moreover, the applied clustering can be adapted by the DSOs in their grid areas, as they applied clustering parameters are most likely to be available at each DSO.

Generally, a separate clustering of the MV grids according to the voltage level (V_n = 10 kV or V_n = 20 kV) has not shown much differentiation in the final clusters. Since the chosen clustering parameters are not dependent on the voltage level but rather on the grid characteristics, the final clusters of the separate clustering according to the voltage level are overlapping.

This correlates with the fact that the integration of the elements of the energy transition is independent of the voltage level in the MV grid, as explained in the scaling down process of EVs, HPs and PV systems. Nevertheless, the required planning measures due to the integration of the elements of the energy transition depend on the voltage. Therefore, the MV grids of $V_n = 20$ kV are technically capable of absorbing more new loads than the MV grids of $V_n = 10$ kV without exhibiting grid limit violations. This note is later discussed in the planning example of a city grid (section 4.4, p. 76) and proven in the 7^{th} PG (section 5.1.7, p. 109).

As for the selection of the representative MV grids, they should be chosen as close as possible to the cluster centre. This ensures that the selected MV grids have the highest validity in representing the MV grids in the corresponding cluster. The results of applying the *k*-means cluster algorithm are shown in the upcoming section.

4.1.3 Selection of Representative Urban Medium-Voltage Grids

Applying the *k*-means clustering algorithm with the previously determined clustering parameters to the MV grid database yields the cluster diagram shown in Figure 4.2 (p. 71). The figure shows the individual MV grids per cluster and the chosen MV grids in addition to the cluster centre. The clusters are clearly differentiated from each other, showing that they have similar characteristics within the cluster yet different characteristics from one cluster to another. Consequently, MV grids are carefully selected to represent the clusters. Moreover, several supplementary MV grids are chosen for further application of the methodology of the strategic grid planning. Thus, a total of eleven grids are chosen as representative MV grids (G01 to G11). These MV grids are referred to in the further context as the “investigated MV grids”. The specific grid parameters of the investigated MV grids are listed in section 8.3 (p. 154) with a classification in terms of the building and urban structure provided in Table 8.2 (p. 154).

Additionally, Figure 4.2 (p. 71) displays the number of MV grids per cluster in the top right corner. The highest number of MV grids is found in cluster 1 followed by cluster 2 and cluster 4. Clusters 5 and 6 represent an equal number of MV grids, whereas cluster 3 represents a limited number of the MV grids.

An analysis of the six generated clusters in terms of the grid parameters is shown in Figure 4.3 (p. 71). The mean value of the grid parameters of the MV grids is shown per cluster. The illustrated analysis shows that the six clusters differ significantly from one another in each of the clustering parameters. For instance, even though cluster 5 and cluster 6 exhibit roughly similar mean line length and a mean number of building connections, they differ significantly in the mean number of metering points as well as the number of secondary substations. These discrepancies can be observed between all clusters, which reflects the success of the applied clustering algorithm in differentiating the MV grids.

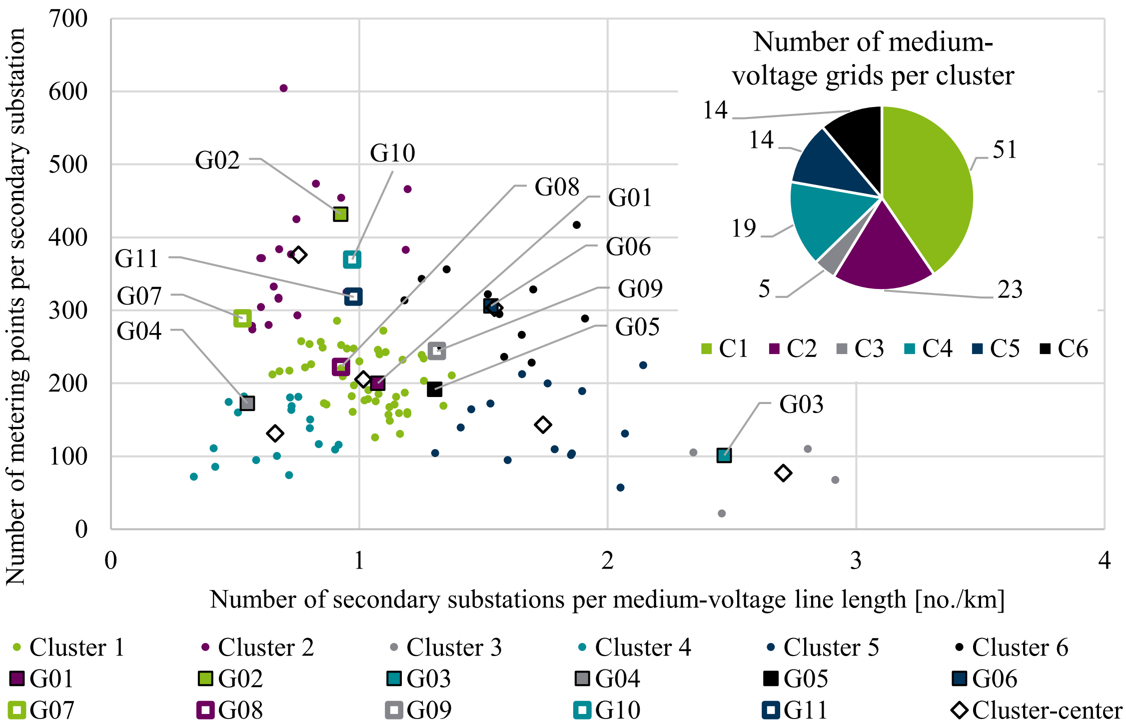

Figure 4.2: Selected representative medium-voltage grids per cluster [40] (C = cluster, G = grid, No. = number)

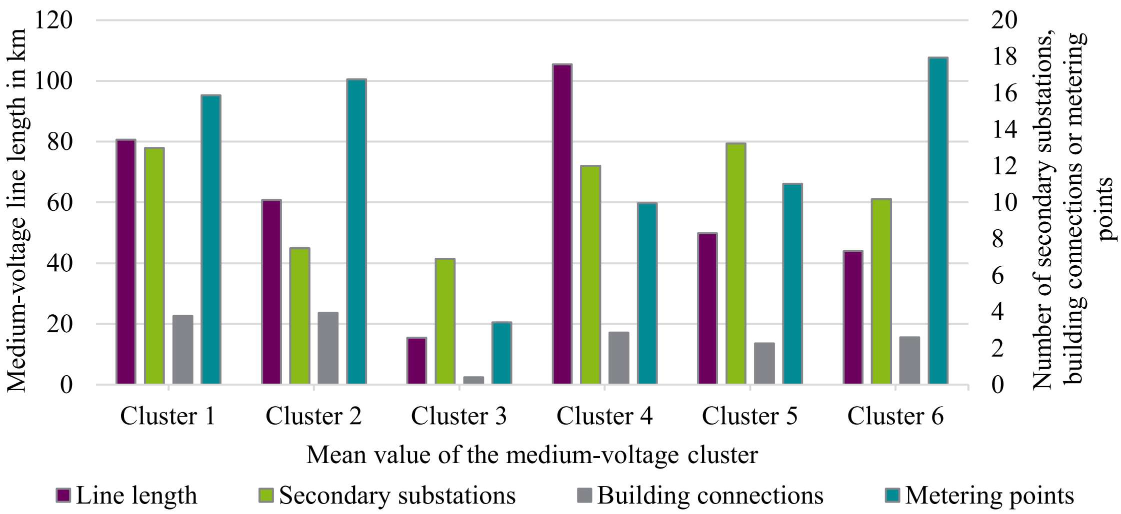

Figure 4.3: Differences in the grid parameters between the medium-voltage clusters [128]

After the representative MV grids are selected, the methodology of the strategic grid planning can be applied. The first step in applying the methodology is to model the conventional loads as well as the new loads and the PV systems in each of the selected MV grids. By modelling the new loads and the PV systems, their impact on the MV grids can be accurately analysed. Since the new loads and the PV systems represent two opposing operating points in the grids, the following section analyses the impact of the elements of the energy transition on few MV grids before performing the strategic grid planning on the chosen MV grids.

4.2 Analysis of the Impact of the Elements of the Energy Transition on Urban Medium-Voltage Grids

Before planning the eleven chosen representative MV grids, a preliminary analysis of a few grids is beneficial for grasping initial planning results. Hence, this section presents an analysis of the impact of the elements of the energy transition before performing the strategic grid planning. The presented analysis focuses on the two operating points, namely, peak load operating point and peak generation operating point, to determine whether the urban MV grids are load dominated or are they generation dominated.

According to the development scenarios for EVs, HPs and PV presented in Chapter 2 and the methodology for modelling these elements in sections 3.4, 3.5 and 3.6, the CPs, the HPs and the PV systems are determined for seven (as a sample) out of the selected eleven representative MV grids. Nevertheless, the conclusion based on the analysis of the shown grids can be expanded to include the missing grids, since the clusters of each of the missing grids (G04, G08, G10, G11) are represented by one of the grids analysed in this section.

The load power as well as the PV generation power per MV grid are shown in Figure 4.4 (p. 73) for the two development scenarios, the three investigation years and the HP of P_{HP} = 9.0 kW from the transformer planning perspective with the corresponding DFs. For readability reasons, the load power values and the PV power values are displayed on two different y-axes due to the discrepancy in their power values. Based on the given load and generation power values, the power in the peak load operating point and the peak generation operating point can be calculated using equation (3.1) – equation (3.4).

The figure shows that the penetration of the elements of the energy transition differs from one grid to another. This difference stems from the different grid characteristics of the investigated grids as well as their different geographical locations, which strongly influence the final number of elements according to the scaling down and distribution processes.

Focusing on the maximum penetration case illustrated in the year 2050 for the progressive scenario and HP of P_{HP} = 9.0 kW, Figure 4.4 shows that the load increase due to the new loads significantly surpasses the generation increase due to the PV systems in all grids except G07. For instance, the highest generation is exhibited by G01 of around $P_{\mathrm{PV}} \cong 5.5$ MW. This is overshadowed by the load increase in the same grid to be around $P_{\mathrm{load}} \cong 15$ MW, which approximates three times the generation increase. For grids G02 and G09, the load increase amounts to more than four times the generation increase in the year 2050 with the progressive scenario. Therefore, the peak generation operating point does not result in line overload in any of the seven grids, whereas the peak load operating point results in several line overloads as shown in the 5$^{\mathrm{th}}$ PG (section 5.1.5, p. 107).

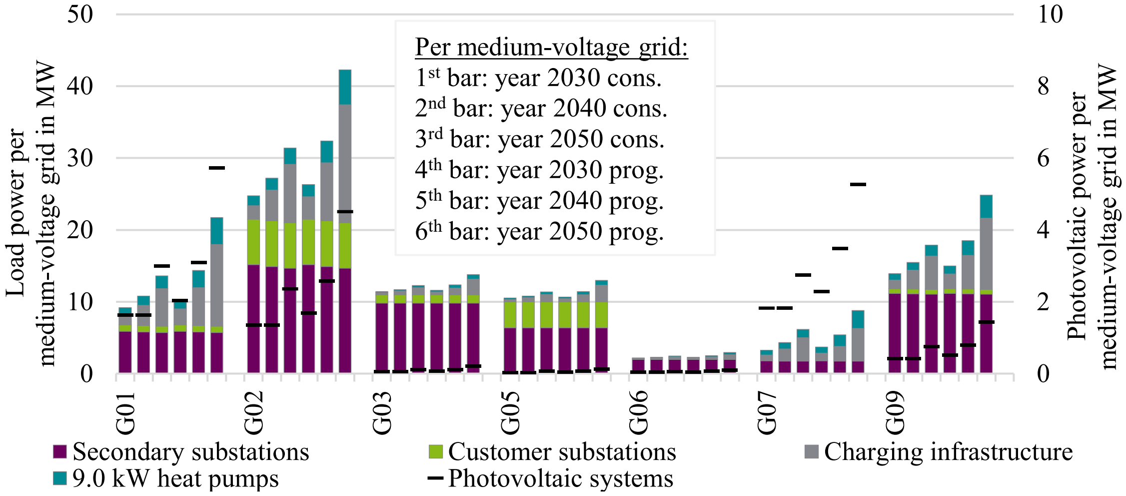

Figure 4.4: The load and photovoltaic power of seven representative medium-voltage grids for the three investigation years and the two development scenarios from the transformer planning perspective (cons. = conservative scenario, prog. = progressive scenario)

Figure 4.5 shows the node voltage of the seven MV grids in the two operating points for the progressive scenario in the year 2050 and $P_{HP} = 9.0$ kW. The minimum and the maximum node voltage are displayed for the peak load operating point and the peak generation point, respectively. The figure clearly shows that none of the grids suffer from a voltage limit violation apart from G07, since it exhibits a nearly equal load and generation increase. After applying conventional planning measures to this specific grid in the peak load operating point, the voltage limit violations in the peak generation operating point are remedied.

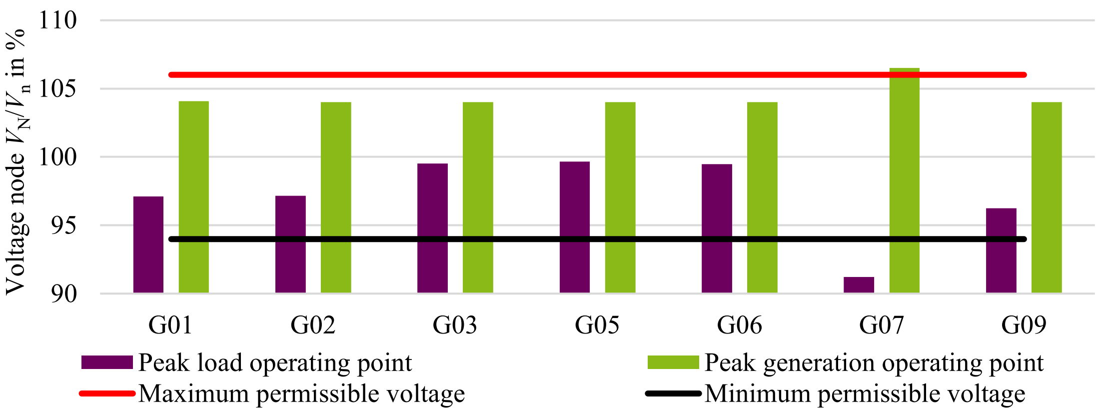

Figure 4.5: The node voltage of seven representative medium-voltage grids for the two operating points in the year 2050 for the progressive scenario and P_{HP} = 9.0 kW along with the permissible voltage limits

This analysis demonstrates that the future power development is predominantly loads oriented. Hence, it can be concluded that the impact of PV systems on urban MV grids is subordinate to the impact of the new loads on urban MV grids. Similarly, [134] confirms that the impact of PV systems in the downstream LV grids is overshadowed by the impact of the new loads in urban LV grids. With the focus on the necessary measures for the strategic planning of MV grids, the PV systems are not further analysed. Based on the methodology of the grid planning explained in Chapter 3 and the representative MV grids selected in section 4.1, the upcoming three sections present three planning examples for three representative MV grids from different urban areas.

4.3 Planning Example of an Inner-city Grid

Starting in this section, an example of an inner-city[16] grid with V_n = 10 kV is shown in Figure 4.6. This inner-city grid feeds 22 secondary substations with a total of 504 building connections in addition to 16 customer substations. The figure shows the geographical topology of the grid including, the grid infeeder, the MV lines and the secondary and customer substations. The grid has a total line length of $l \cong 17$ km and is supplied through a HV/MV transformer of S_r = 40 MVA. For the single case contingency, a second HV/MV transformer is available in the primary substation.

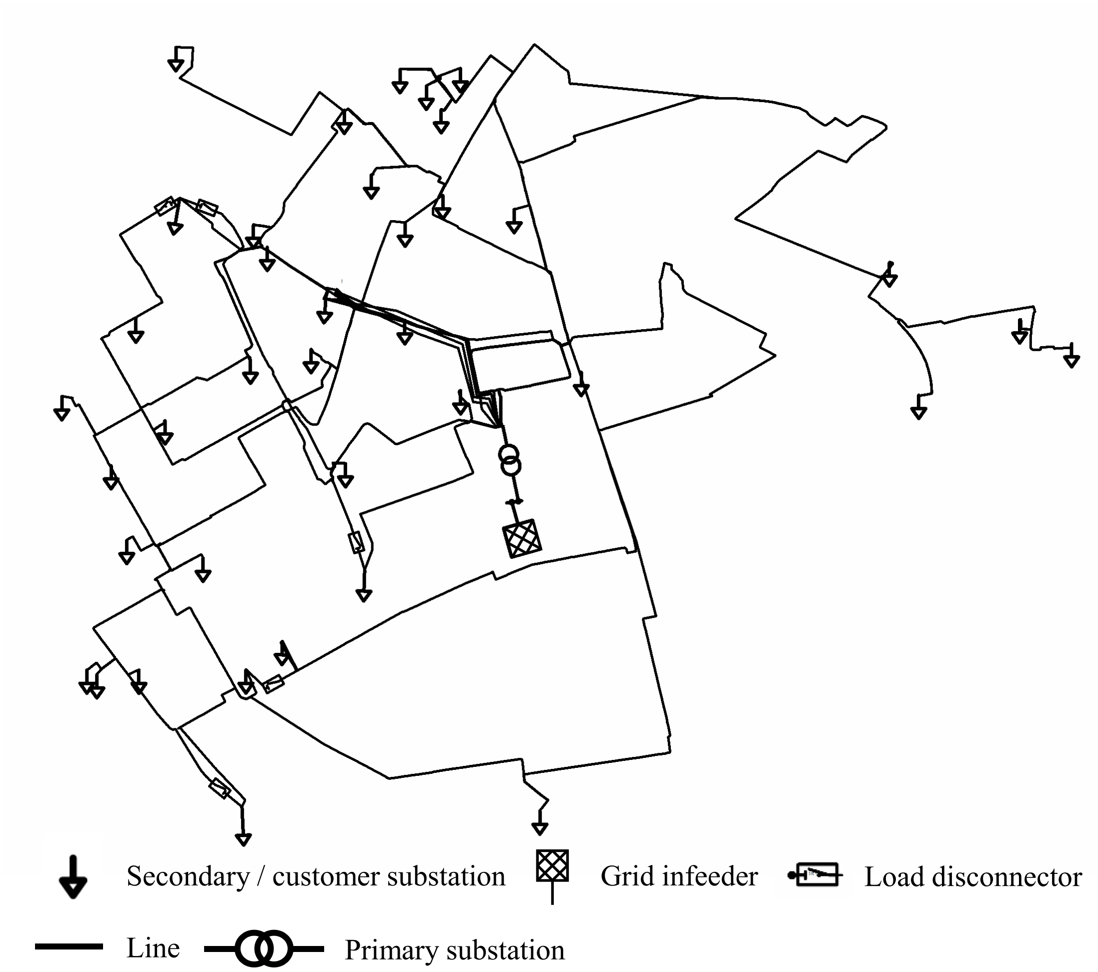

Figure 4.6: Geographical topology of the inner-city grid

According to the scaling down and distribution process for EVs (section 3.4.1) and HPs (section 3.5.1), the penetration of the new loads is calculated in the inner-city grid. The following Table 4.1 (p. 75) shows the number of prCPs, puCPs and HPs over the three investigation years in the inner-city grid for the two scenarios. The number of ufCPs is included in the number of puCPs in the table, as they both represent the publicly accessible charging infrastructure.

[16] Inner-city areas are areas with large building size, very dense built-up area density, compact building shape and not squared buildings without a particular orientation. [135]

The forecasted PV systems in the inner-city grid are intentionally not included in the upcoming analysis, since it has already been determined in section 4.2, that the impact of the PV systems on the urban MV grids is insignificant in comparison to the impact of the load development.

The table shows that the expected number of HPs is limited, as the inner-city grids are dominated by multistorey buildings with a limited space potential for installing HPs. It also shows that a limited number of puCPs are expected in this grid area in comparison to prCPs.

Table 4.1: Number of charging points and heat pumps in the inner-city grid over the investigation years and the scenarios (prog. = progressive scenario, cons. = conservative scenario)

Investigation year	Private charging points		Public charging points		Heat pumps	
	Prog.	Cons.	Prog.	Cons.	Prog.	Cons.
2030	315	190	25	13	29	24
2040	734	391	57	29	55	29
2050	1,617	746	128	57	87	41

The expected number of CPs and HPs is then transformed into power values, which represent the load development of the new loads in the inner-city grid. The power values are displayed in Figure 4.7 (p. 76), which shows the power for prCPs, puCPs and the three HP models over the investigation years and for the two scenarios in addition to the conventional load development from the transformer planning perspective.

Starting with the conventional load development, it is clear that the conventional load remains nearly constant over the investigation years and its development is negligible. Moving on to the new loads, the figure shows that the prCPs account for the highest load power development over the three investigation years and the two scenarios. Whereas, the puCPs represent a fraction of the power with a maximum $P_{\text{load}} \cong 0.5$ MW in the year 2050 in the progressive scenario. As for the HPs, by considering the HP with $P_{\text{HP}} = 9$ kW it can be concluded that the HPs represent around one-third of the added power. The total power, including the new loads, amount to $P_{\text{load}} \cong 13$ MW in the year 2050 with the progressive scenario. Thus, a transformer overload is unexpected in the grid.

This increase in the load power is then modelled in the MV grid according to the methodology explained in sections 3.3, 3.4 and 3.5. Consequently, the grid state is analysed regarding the identified grid limits given in section 3.7. An analysis of the inner-city grid in the year 2050 for the progressive scenario and the HP with $P_{\text{HP}} = 9$ kW in the peak load operating point from the feeder planning perspective, which corresponds to the maximum investigated load situation, shows that the grid state exhibits no grid limit violations. Hence, no planning measures are required in this case for the planning example of the inner-city grid. Therefore, PAs are not generated.

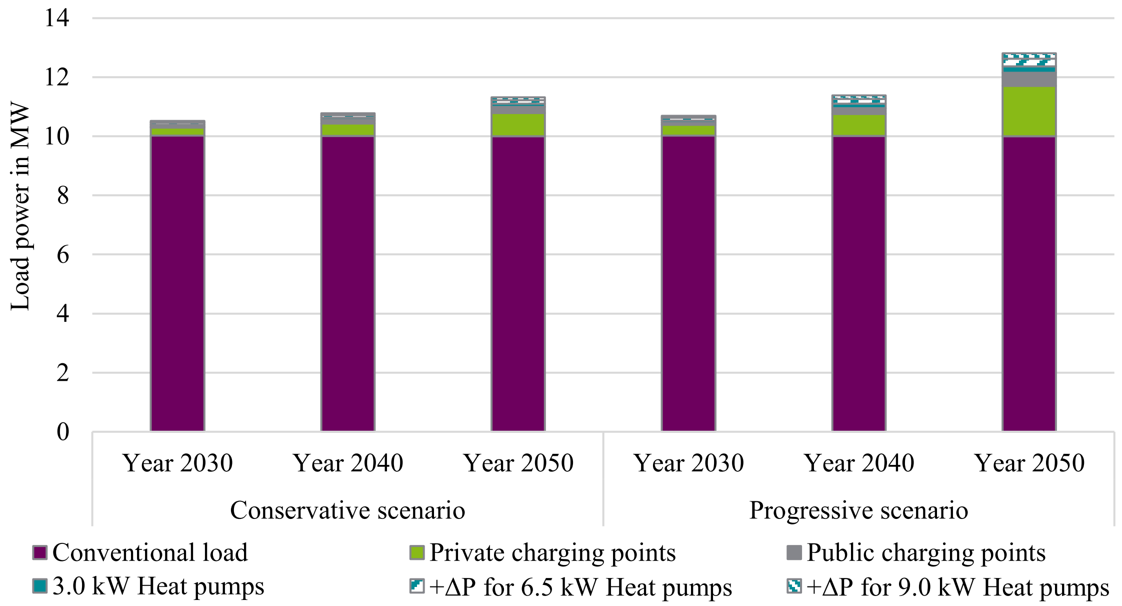

Figure 4.7: Power per load type from the transformer planning perspective for each scenario and investigation year for the inner-city grid

4.4 Planning Example of a City Grid

Moving outwards from the urban centre represented by the previous planning example of an inner-city grid, this section presents a planning example of a city grid. As the definition suggests, the urban area lies further from the inner-city area with a slightly lower building and residential density but still exhibits the urban structure of multistorey residential buildings. Figure 4.8 (p. 77) shows the schematic diagram of the chosen city grid.

Due to the grid's complexity having two intertwined MV grid parts of two voltage levels, a schematic diagram is chosen to improve the visibility of the grid structure. The MV grid consists of two MV grid parts operated at the two voltage levels $V_n = 10$ kV and $V_n = 20$ kV. These two grid parts are supplied through two three-winding transformers each with $S_r = 63$ MVA from $V_n = 110$ kV to their respective voltage levels. The city grid part of $V_n = 20$ kV consists of eleven feeders that supply 28 customer substations and 43 secondary substations with a total of 1,433 building connections and a total line length of $l \cong 66$ km. The city grid part of $V_n = 10$ kV spreads over 18 feeders that supply 18 customer substations and 88 secondary substations with a total of 3,186 building connections and a total line length of $l \cong 69$ km.

It must be noted that it is not common to operate urban distribution MV grids with two separate voltage levels. Nevertheless, such a constellation has most probably arisen over the course of the historic development of the MV grids over the years. In this specific planning example, the two grid parts are analysed as two separate, independent MV grids. The loading of the transformers, on the other hand, is specified by summing the load power in the two grid parts.

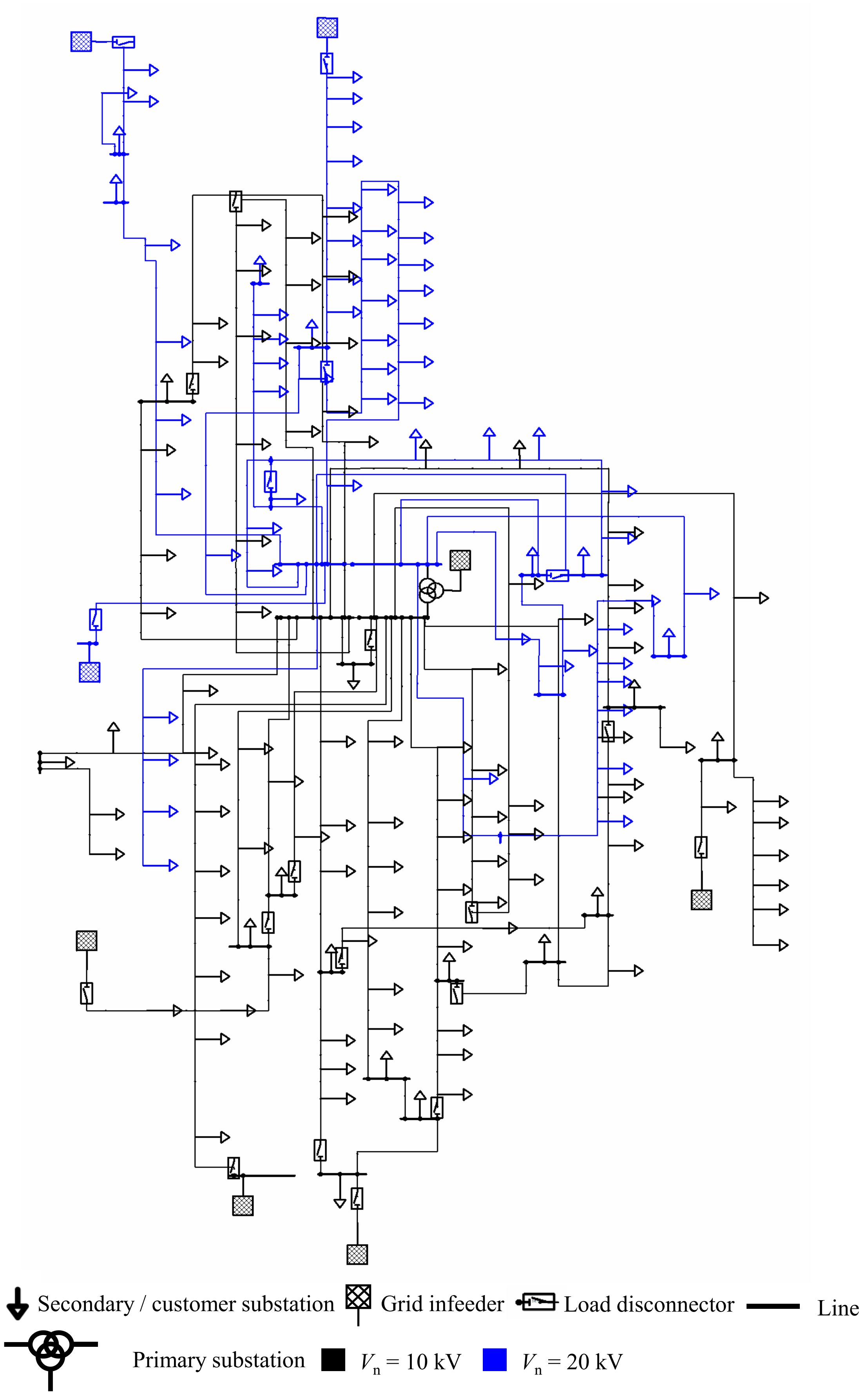

Figure 4.8: Schematic diagram of the city grid

Even though, the displayed constellation of two grid parts supplied from the same primary substation is not very common and is not representative of the majority of the MV grids, this specific urban grid is investigated for the following reasons:

1. This specific constellation exists in several MV grids from the MV grid database analysed in section 4.1. Therefore, it is assumed that – rare as it may – it can be found at DSOs around Germany and in extension Europe and the world.
2. The simultaneous investigation of two grids parts of two different voltage levels (V_n = 20 kV and V_n = 10 kV) gives a clear comparison of the impact of the new loads on the different voltage levels. Since the two grid parts coexist in the same urban area, the distribution factors applied in the scaling down and the distribution process (section 3.4.1 and section 3.5.1) are identical. Consequently, the difference in the impact of the new loads on the two grid parts can be attributed to the different voltage levels.

Therefore, the following analysis focuses not only on the strategic planning of a city grid but also on the differences between the two grid parts.

The scaling down and distribution of the chosen scenarios for the city grid results in the number of new loads displayed in Table 4.2 (p. 78). The table lists the number of prCPs, puCPs and HPs for the three investigation years and the two scenarios for each of the two grid parts. The number of ufCPs is summed to the number of the puCPs in the table as they both represent the publicly accessible charging infrastructure. The forecasted PV systems in the city grid are intentionally not included in the upcoming analysis, since it has already been determined in section 4.2, that the impact of the PV systems on the urban MV grids is insignificant in comparison to the impact of the load development. As the foreseen number of new loads is strongly dependent on the building structure, it can be roughly deduced that the number of new loads (CPs and HPs) between the two grid parts is proportional to the ratio of the number of the building connections. Similar to the number of new loads in the inner-city grid (see Table 4.1), the expected number of prCPs significantly exceeds the number of puCPs.

Table 4.2: Number of charging points and heat pumps in the city grid over the investigation years and the scenarios (prog. = progressive scenario, cons. = conservative scenario) (Values in the first and the second column of each scenario is for the grid part V_n = 10 kV and V_n = 20 kV, respectively)

Investigation year	Private charging points				Public charging points				Heat pumps			
	Prog.		Cons.		Prog.		Cons.		Prog.		Cons.	
2030	1,743	1,176	1,015	727	149	67	91	36	189	86	146	67
2040	3,950	2,776	2,040	1,614	347	156	198	92	357	160	184	81
2050	8,520	6,304	3,819	3,041	782	355	374	164	562	254	258	116

The calculated number of CPs and HPs results in the power per load type displayed in Figure 4.9. The figure differentiates between the two voltage levels in the grid as well as prCPs, puCPs, and HPs for the three investigation years and the two scenarios in addition to the conventional load from the transformer planning perspective. Similar to the power values shown in Figure 4.7, the conventional load remains nearly constant over the investigation years. Moreover, the power values for the prCPs in this case also represent the highest share of power with a total of $P_{\mathrm{load}} \cong 16$ MW in the year 2050 for the progressive scenario while considering the two voltage levels. Moreover, the total grid load power amounts to $P_{\mathrm{load}} \cong 76$ MW. Thus, an overload of the transformer is expected, which can be remedied either by conventional or innovative measures.

Figure 4.9 shows that the power value for all new load types in the year 2050 for the conservative scenario is approximately equal to the power value for all new load types in the year 2040 for the progressive scenario. This is reflected in the required line measures shown in Figure 4.11 (p. 81).

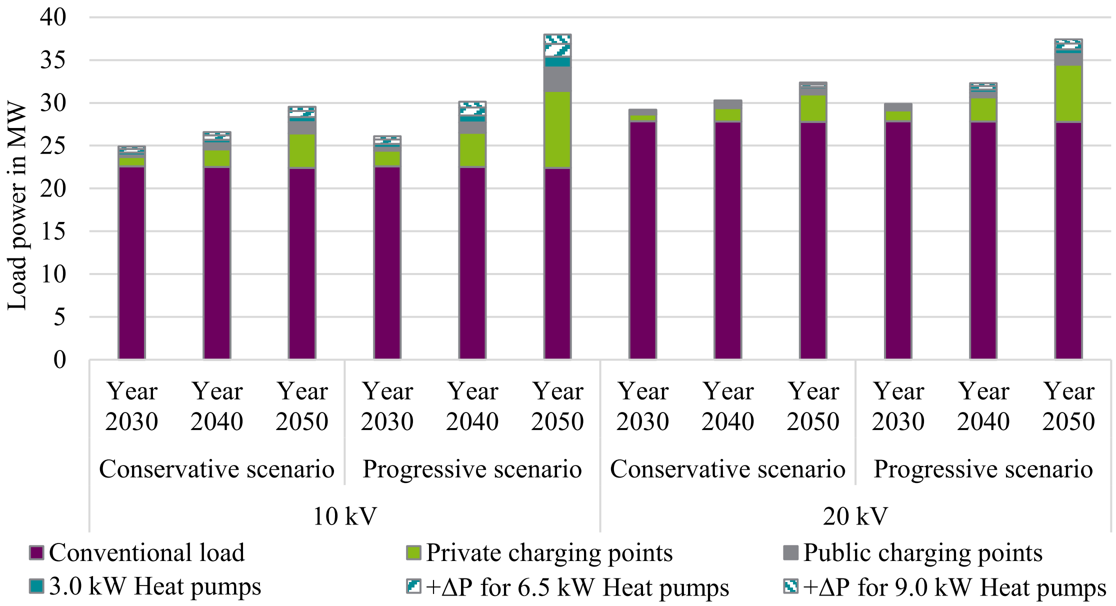

Figure 4.9: Power per load type from the transformer planning perspective for each scenario and investigation year for the city grid

The calculated load power development is then modelled in the grid from the feeder planning perspective to determine whether any grid limit violations would occur. Accordingly, the city grid state from the feeder planning perspective in the year 2050 with the progressive scenario and the HP of $P_{\mathrm{HP}} = 9$ kW is shown in Figure 4.10 (p. 80). In contrast to the inner-city grid, several line overloads arise in the city grid. Specifically, the line overloads are limited to the grid part with $V_{\mathrm{n}} = 10$ kV, without line overloads occurring in the grid part with $V_{\mathrm{n}} = 20$ kV. These line overloads are mostly limited to the line sections at the beginning of the respective feeder. In the same feeder, there are line sections of a relatively higher cross-section area between the line sections of a small line cross-section area. Hence, there are line sections in between the overloaded line sections that are not overloaded.

As for the node voltage, there are no voltage range violations occurring in the grid.

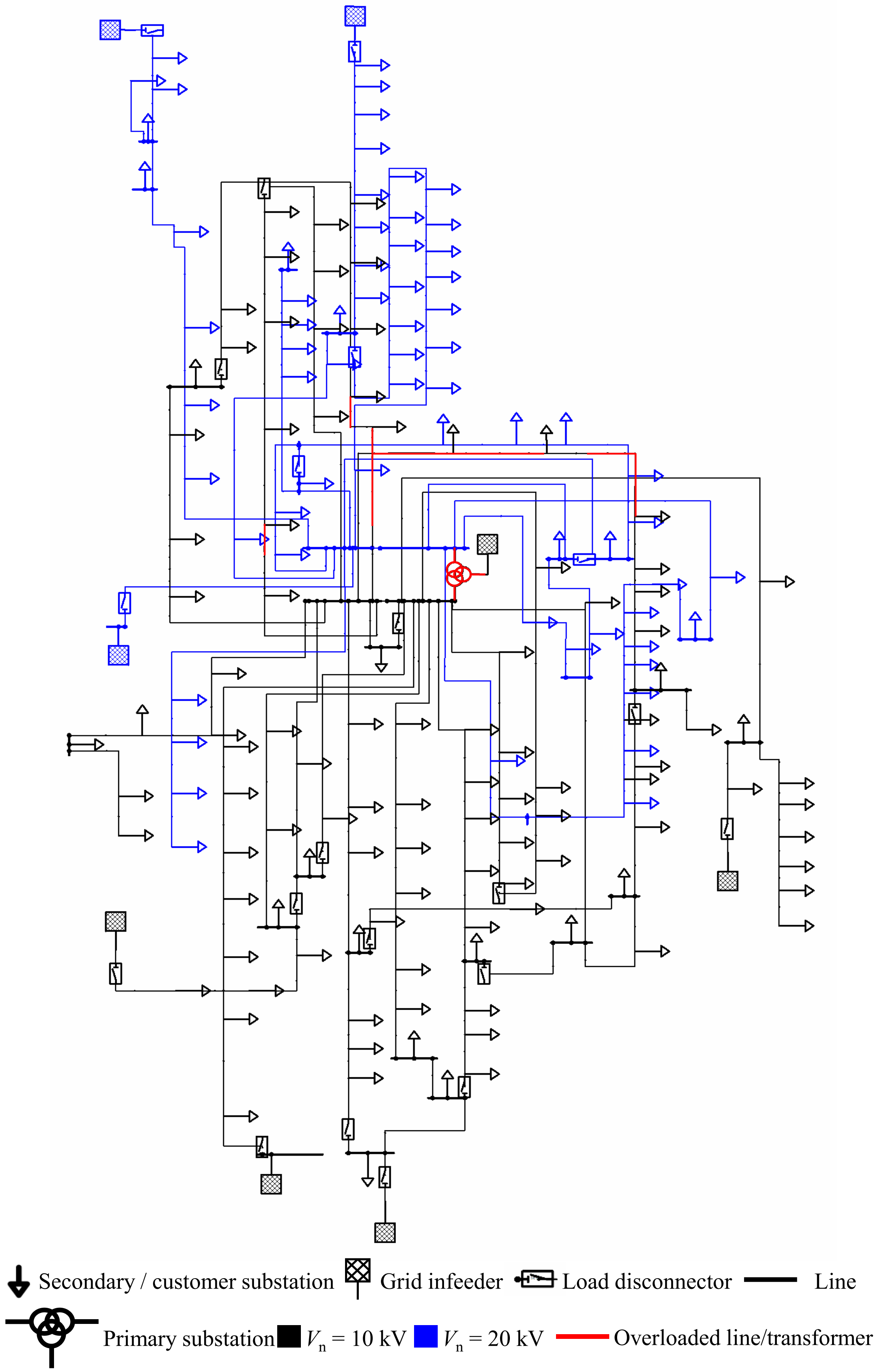

Figure 4.10: Grid state of the city grid in the year 2050 with the progressive scenario and the HP of P_{HP} = 9 kW at the peak load operating point from the feeder planning perspective

According to the identified grid state, several PAs are applied. Figure 4.11 shows the required total line measures to remedy the occurring line overloads for the investigated PAs. A differentiation between the investigation year, the development scenario and the HP model is shown as well. Since line overloads only occur in the progressive scenario in the year 2050, line measures are not required in the conservative scenario nor the years 2030 and 2040 with the progressive scenario. Therefore, no line measures are demonstrated in the figure in these cases.

To remedy these line overloads using conventional planning measures, line measures are required with a total line length of $l \cong 1.5$ km in the progressive scenario with the HP of $P_{HP} = 9$ kW. For the same case, the LM-V2 can reduce the required line measures to $l \cong 1.4$ km, whereas the LM-V1 can completely eliminate the line measures. As for the LM-V3, the required line measures cannot be reduced. On the other hand, ES can reduce the required line measures to $l < 200$ m. By applying ES, there is no differentiation of the required line measures between the three HP models, as the difference in the load power is compensated by increasing the power of the ES.

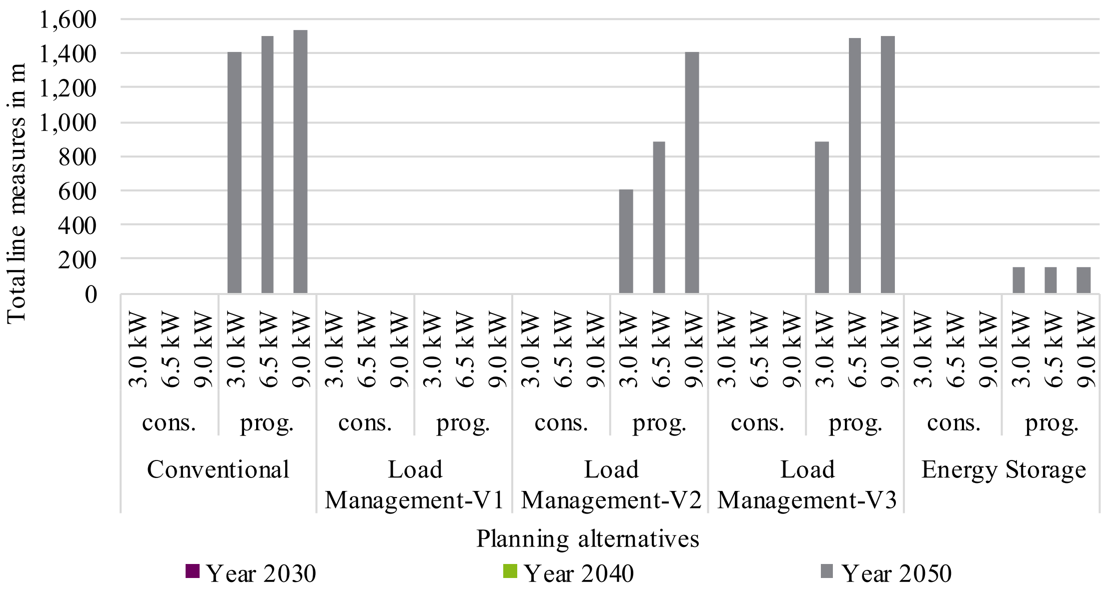

Figure 4.11: The total line measures for the conventional and the innovative planning alternatives for the urban medium voltage grid shown according to the heat pump model, the development scenario and for the investigation year 2050 (cons. = conservative, prog. = progressive)

Building on the required line measures, Figure 4.12 (p. 82) shows the line measures in relation to the total line length of the grid for the different PAs according to the scenario and the HP model. In the conventional as the LM-V3 PAs, the required line measures amount to around 1.1 % of the total line length of the grid. This percentage decreases by applying LM-V2 and drops down to around 0.1 % by applying ES.

The demonstrated percentage of the line measures gives the DSO an indication of the expected line measures in their respective grids.

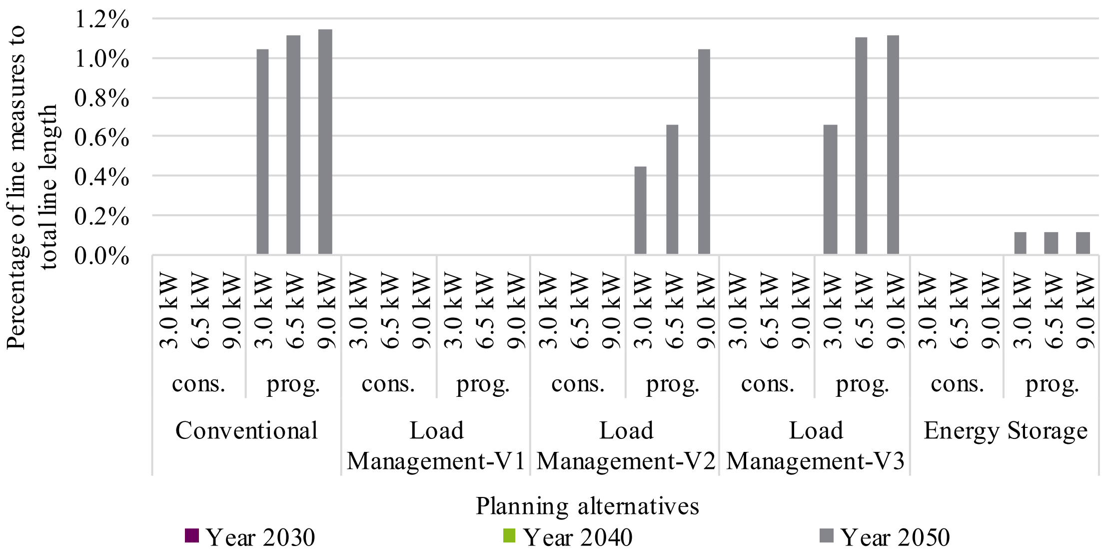

Figure 4.12: Percentage of line measure to the total line length of the city grid for the different planning alternatives according to the scenario and the heat pump model

Figure 4.13 shows the costs for applying conventional and innovative planning measures and technologies to remedy the grid limit violations consolidated for the two scenarios and the three HP models. Since the planning measures occur in the year 2050, all PAs have a significant residual cost value shown in the figure. The costs for the conventional planning measures can exceed or be less than the required costs for applying any of the LM variants depending on the applied LM layout. The cheapest PA is the innovative technology LM-V1 with the layout (0) as the costs for the MICT infrastructure are not considered. The costs then increase as the LM layout increasingly considers the MICT infrastructure. By comparing the LM layouts, the costs of LM-V3 exceed the costs of LM-V2. Of all the PAs, the most expensive PA is the innovative technology ES. Thus, it is the least favourable PA for the city grid from the cost perspective.

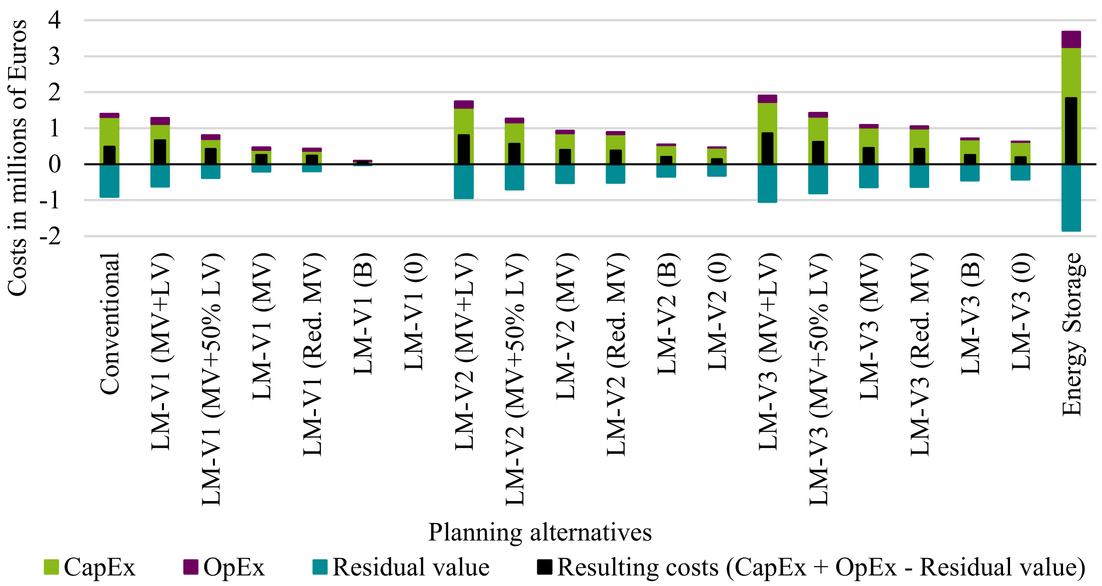

Figure 4.13: Net present value costs in millions of Euros for the planning alternatives of the city grid for the two scenarios and the three heat pump models (CapEx = Capital Expenditure, OpEx = Operational Expenditure) (Net present value for the start year 2021)

As an extension to the above-shown cost calculation, Figure 4.14 presents the results of the alternative assessment model for the five assessment criteria and the five assessment strategies. Due to visibility restrictions, only the results of the LM layout (MV) are displayed. Nevertheless, an indication of the faded-out LM layouts can be deduced by utilising the values shown in Figure 4.13. Among the PAs, LM-V1 (MV) achieves the highest score in all assessment strategies except for the technically oriented assessment strategy, in which it achieves a score close to the ES. The equal assessment strategy puts the ES ahead of the conventional planning, as it considers the less frequency of failure and the less effort of construction offered by ES. This is highlighted in the assessment strategies conservation of resources and grid resilience. The LM-V2 (MV) and the LM-V3 (MV) achieve nearly similar results in all the assessment strategies.

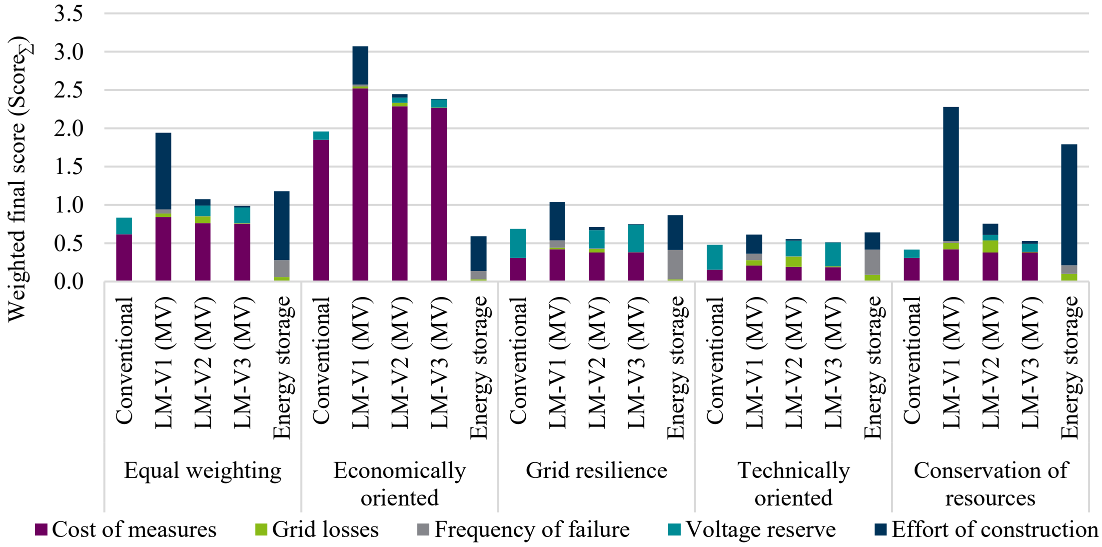

Figure 4.14: Results of the alternative assessment model for the city grid for the progressive scenario with the heat pump model of P_{HP} = 9 kW based on [40]

4.5 Planning Example of a Suburban Grid

Moving further towards the city outskirts, this section presents a planning example of a suburban[17] grid with V_n = 10 kV. The suburban area lies on the outskirts of urban areas and exhibits a much lower density of residential and commercial buildings in comparison to the inner-city and city areas. A suburban area is mainly predominated by detached and semi-detached houses with a significantly low density of buildings.

Figure 4.15 shows the geographical topology of the investigated suburban grid. The grid has 14 feeders that supply 18 customer substations and 37 secondary substations with a total of 4,041 building connections and a total line length of around $l \cong$ 40 km. The grid is supplied through two transformers, each with S_r = 40 MVA.

[17] Suburban areas are areas with medium and small building size, low built-up area density, compact building shape and squared buildings without a particular orientation. [135]

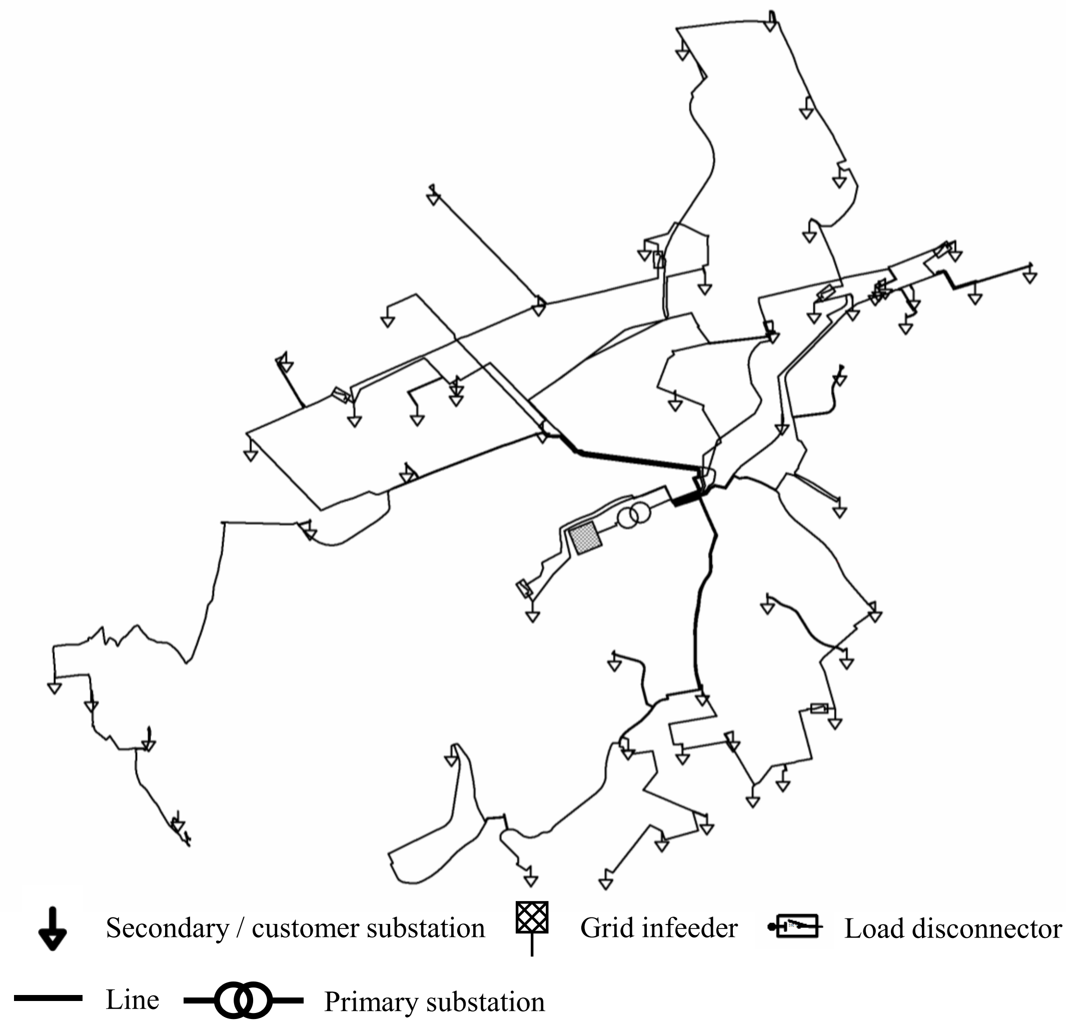

Figure 4.15: Geographical topology of the suburban grid

According to the scaling down and distribution methodology, the chosen scenarios are used to determine the number of CPs and HPs in the suburban grid. The following Table 4.3 (p. 85) gives the number of prCPs, puCPs, and HPs for the three investigation years and the two scenarios. The number of ufCPs is summed to the number of puCPs in the table as they both represent the publicly accessible charging infrastructure.

Table 4.3 proves, as established in the previous two planning examples (see Table 4.1 and Table 4.2), that the foreseen number of prCPs clearly exceeds the number of puCPs in each of the investigation years and scenarios. Even though the suburban grid is much smaller than the previously presented city grid in terms of building connections and secondary substations, the expected number of new loads in the suburban grid is nearly equal to the expected number for the city grid. Thus, it can be deduced that the expected penetration of new loads in the suburban areas is higher than in the city areas, which is in term higher than in the inner-city areas.

Table 4.3: Number of charging points and heat pumps in the suburban grid over the investigation years and the scenarios (prog. = progressive scenario, cons. = conservative scenario)

Investigation year	Private charging points		Public charging points		Heat pumps	
	Prog.	Cons.	Prog.	Cons.	Prog.	Cons.
2030	2,531	1,521	195	116	235	186
2040	5,863	3,102	456	241	444	229
2050	11,016	5,564	998	464	708	323

According to the power value assumptions presented in section 3.4.2 and section 3.5.2, the power of the foreseen number of new loads is calculated and presented in Figure 4.16 (p. 85). The figure shows the power per load type for the three investigation years and the two scenarios from the transformer planning perspective for the suburban grid.

The results show that the expected high number of prCPs is reflected in the power values. The figure demonstrates that the power value for prCPs of the suburban grid in the year 2050 for the progressive scenario amounts to $P_{\text{load}} \cong 11.5$ MW, with the consolidated power value for the new loads in the same case reaching $P_{\text{load}} \cong 20$ MW. In the year 2050 for the progressive scenario, the load power due to the new loads becomes nearly equal to the current conventional load in the grid. Nevertheless, an overload of the transformers is unexpected due to the integration of the new loads into the grid.

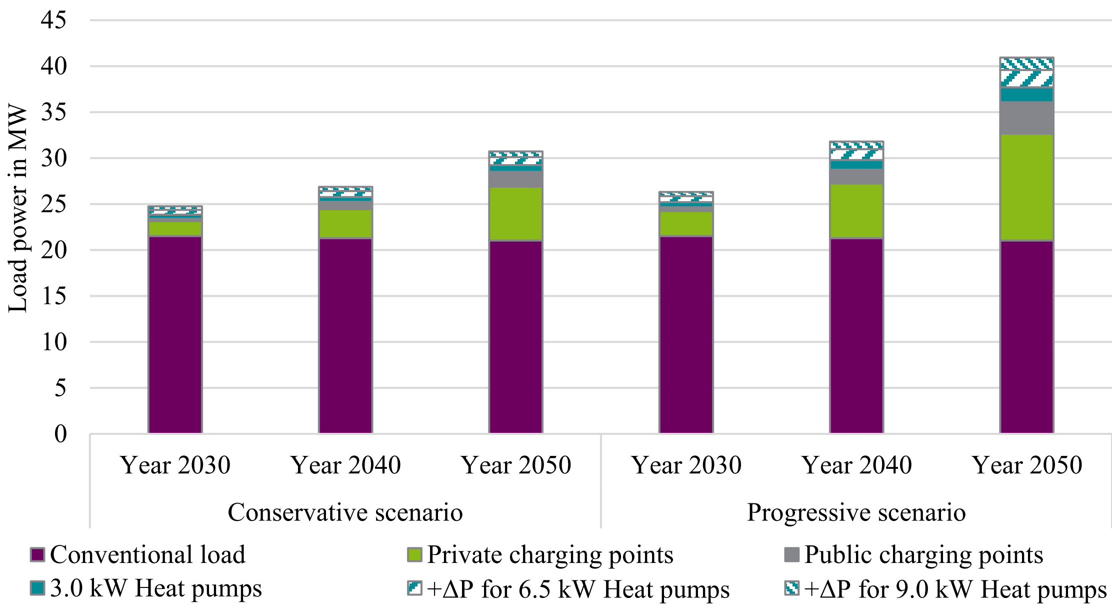

Figure 4.16: Power per load type from the transformer planning perspective for each scenario and investigation year for the suburban grid

The penetration of the new load types is reflected in the grid limit violations. The following Figure 4.17 shows the grid state of the suburban grid in the investigation year 2050 for the progressive scenario and the HP with $P_{HP} = 9$ kW at the peak load operating point from the feeder planning perspective. The figure demonstrates that the integration of new load types leads to line overloads in nearly each of the feeders. The extent of the line overloads depends on the current loading of the feeder as well as the laid line cross-section area and type. In contrast to the inner-city grid and the city grid, line overloads are widespread in the suburban grid.

As for the node voltage, there are no voltage range violations occurring in the grid.

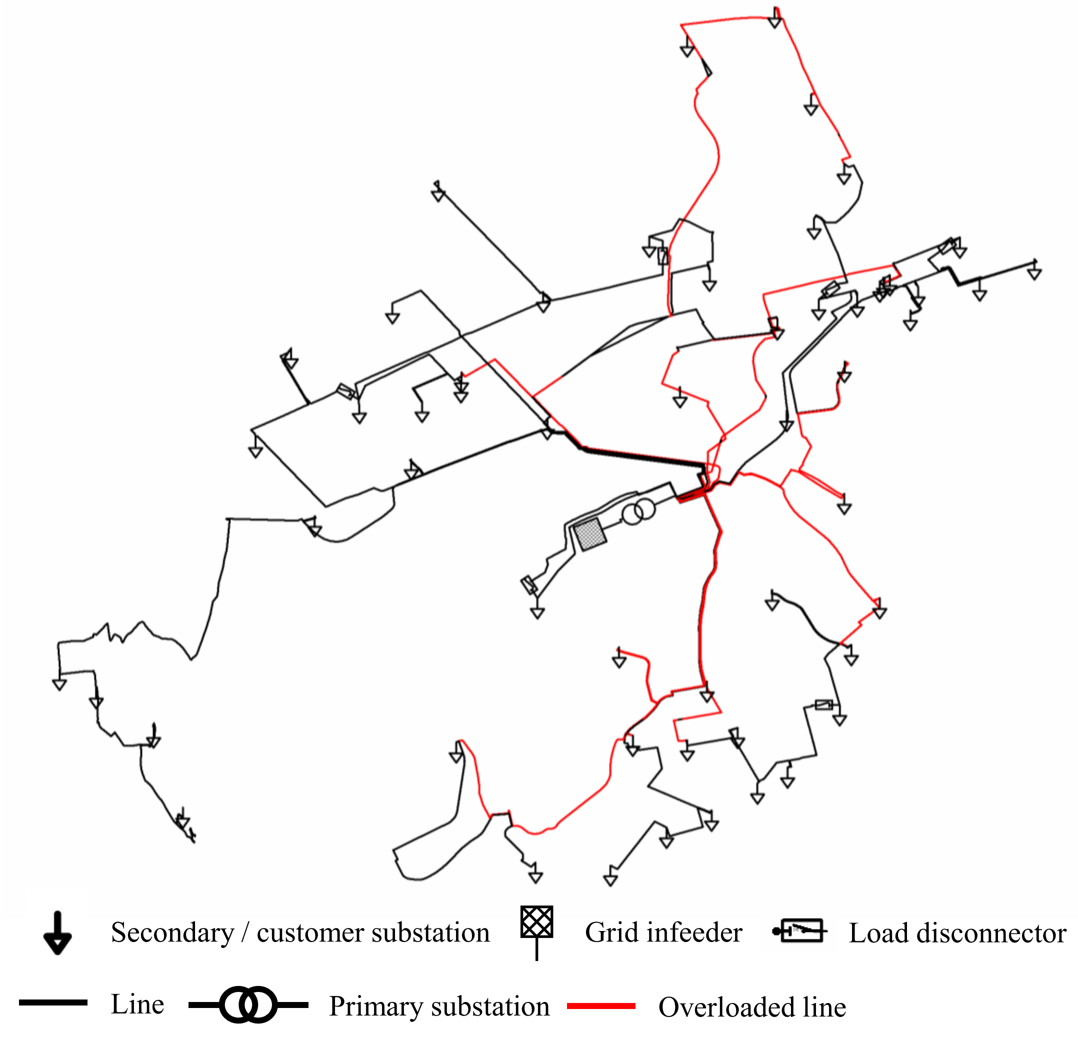

Figure 4.17: Grid state of the suburban grid in the year 2050 with the progressive scenario and the HP of $P_{HP} = 9$ kW at the peak load operating point from the feeder planning perspective

The occurring line overloads are then remedied by conventional and innovative planning measures and technologies. Figure 4.18 (p. 87) shows the line measures for the applied PAs for the suburban grid with differentiation of the HP models and the scenarios. To remedy the occurring line overloads in the progressive scenario with HP of $P_{HP} = 9$ kW using conventional planning measures, line measures have to be performed with a total line length of $l \cong 11$ km.

By applying innovative planning technologies, the required line measures can be significantly reduced. For the LM-V2, a total line length of $l \cong 6.5$ km is required. The required line length is further reduced to $l \cong 3.9$ km by applying LM-V1 with no differentiation between the HP models as they are likewise regulated independent of their HP power. LM-V3 and ES require an approximately equal line length of $l \cong 8$ km.

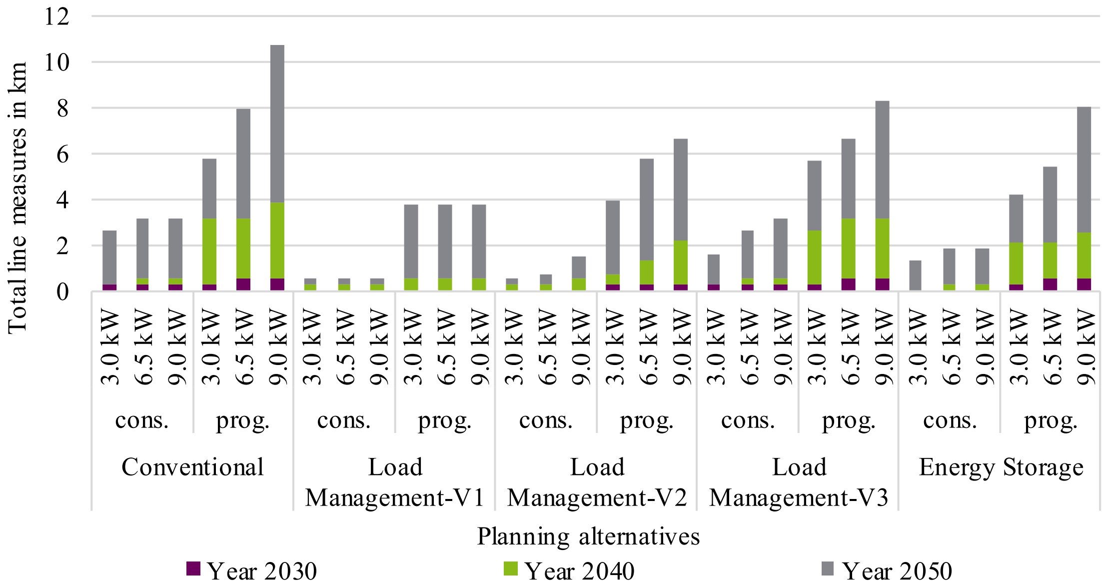

Figure 4.18: The total line measures for the conventional and the innovative planning alternatives for the suburban medium voltage grid shown according to the heat pump model, the development scenario, and the investigation year (cons. = conservative, prog. = progressive)

Depending on the required line measures in each of the PAs, the share of line measures to the total line length in the grid is calculated for each HP model and scenario and demonstrated in Figure 4.19 (p. 88). The required line measures for the conventional PA in the year 2050 with the progressive scenario amount to around one-quarter of the total line length of the grid. As for LM-V1, the required line measures represent 10 % of the total line length. The remaining PAs require line measures varying from 10 % to 20 % of the total line length. The demonstrated percentage of the line measures gives the DSO an indication of the expected line measures in their respective suburban grids.

The costs for remedying the line overloads according to the conventional and innovative planning measures and technologies are consolidated for the two scenarios and shown in Figure 4.20 (p. 88). The costs for the different LM variants increase gradually by considering the MICT infrastructure, which is represented by the different LM layouts. Depending on the LM layout, the figure shows that the required costs for applying the conventional planning measures are nearly equal to the costs for the LM-V3 and LM-V2. The most cost-efficient PA is LM-V1 (0), whereas the most expensive PA is ES.

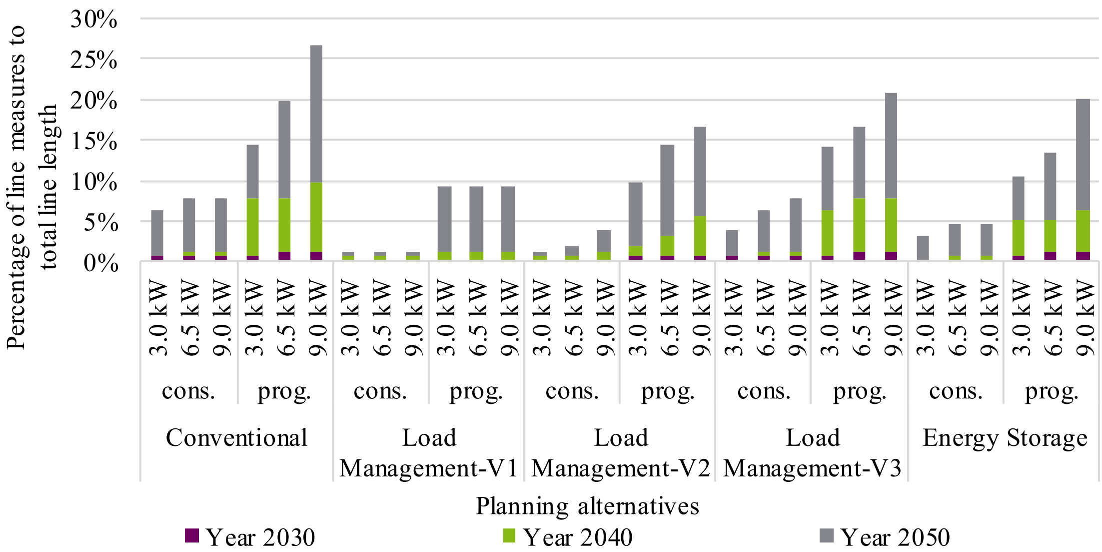

Figure 4.19: Percentage of line measure to the total line length of the suburban grid for the different planning alternatives according to the scenario and the heat pump model

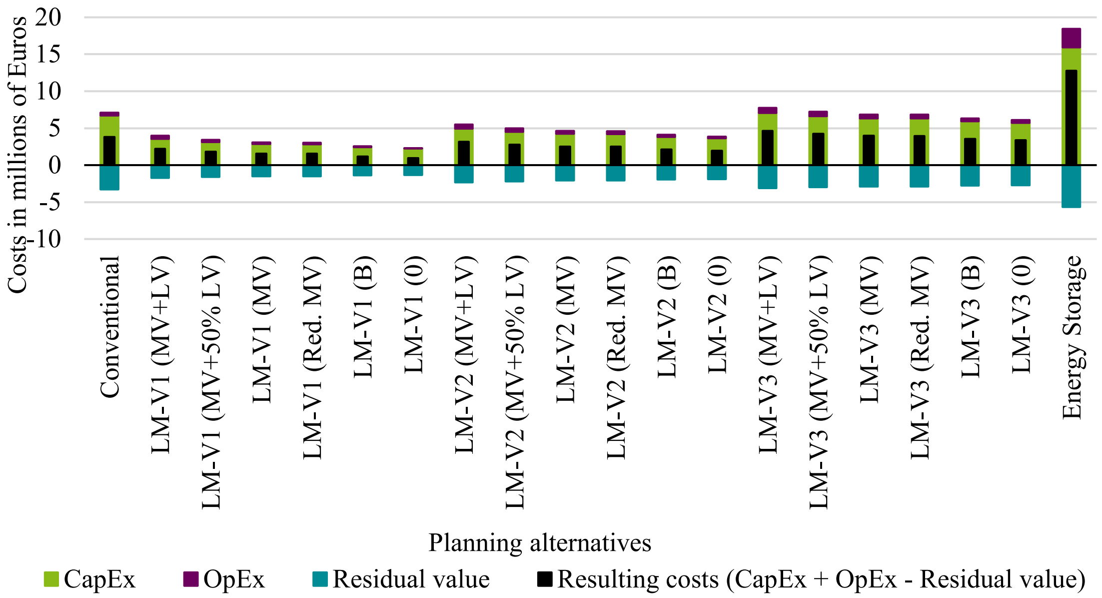

Figure 4.20: Net present value costs in millions of Euros for the planning alternatives of the suburban grid for the two scenarios and the three heat pump models (CapEx = Capital Expenditure, OpEx = Operational Expenditure) (Net present value for the start year 2021)

To further evaluate the fitness of the PAs, Figure 4.21 (p. 89) depicts the results of the alternative assessment model for the suburban grid for the progressive scenario and the HP of $P_{HP} = 9$ kW. The results focus on the maximum penetration case of the new loads into the grids. Due to visibility restrictions, only the results of the LM layout (MV) are displayed. Nevertheless, an indication of the faded-out LM layouts can be deduced by utilising the values shown in Figure 4.20. LM-V1 (MV) has the highest score over all the assessment strategies, thus making it the most favourable PA. It is closely followed by LM-V2 (MV) and LM-V3 (MV). The conventional PA exceeds the ES in the economically oriented assessment strategy. Otherwise, both PAs have an approximately equal score across the assessment strategies.

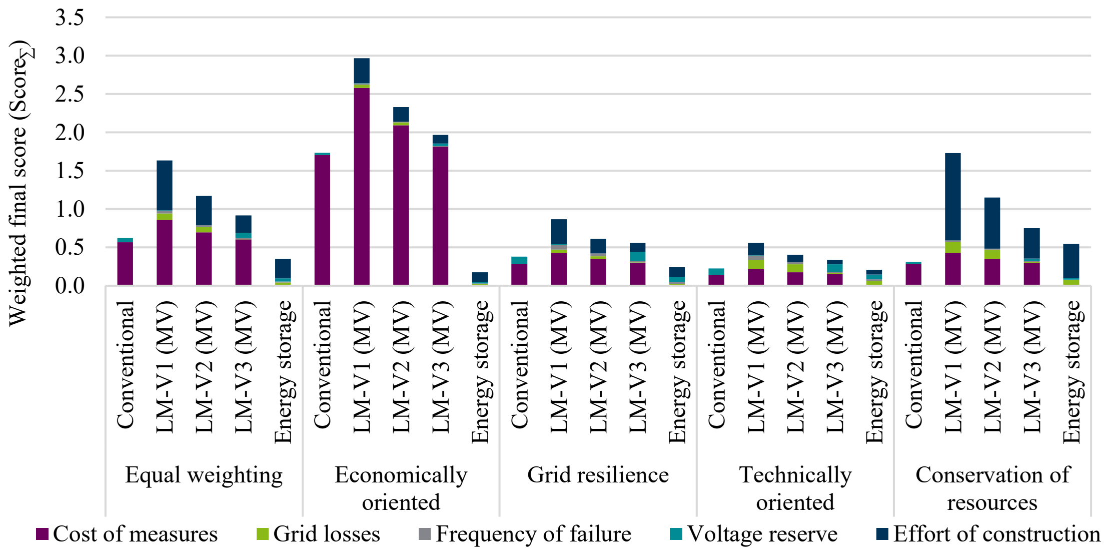

Figure 4.21: Results of the alternative assessment model for the suburban grid for the progressive scenario with the heat pump model of P_{HP} = 9 kW based on [40]

4.6 Findings of the Three Planning Examples

Based on the aforementioned planning examples, this section aims to summarise the analysis presented in the individual planning examples. The goal is to compare and investigate the individual results of each of the planning examples to discover general findings that can be used in deducing the PGs.

By analysing the presented planning examples of the urban grids, several findings are deduced.

The first finding focuses on the absolute number of new loads and their corresponding power value. By considering the different grid dimensions of the planning examples, it can be concluded that the total power of the new loads in the suburban grid in the year 2050 clearly exceeds the corresponding total power value in each of the city grid parts as well as the inner-city grid. Moreover, the absolute number of new loads in the city grid exceeds their corresponding number in the inner-city grid. According to the grid's geographical location, the inner-city centres are usually dominated by multistorey buildings and a high density of commercial buildings. The multistorey residential buildings lack, in most cases, the space for installing a HP and do not ordinarily have private parking spots where prCPs can be installed. As for commercial buildings, their electrification of the heating system requires big-scale HPs, which are considered individual cases as the heat demand differs greatly from one commercial building to another. Hence, it can be concluded that the foreseen penetration of the new loads in inner-city grids is limited. Even though the relative number of new loads to building connections remains constant over all investigated grids, the high absolute number of new loads corresponds to a higher load development. As the penetration of the new loads is strongly dependent on the geographical location of the grid, it can be deduced that the penetration of the new loads increases from the inner-city of the urban centres towards the outskirts of the urban areas.

Building on the load development, the second finding focuses on the occurring grid limit violations. The differentiated penetration of the new loads results in a different grid situation, as exhibited by the line overloads in the city grid. Starting with the line overloads happening in the different grids, the evidence shows that the suburban grid exhibits much more line overloads in contrast to the city grid and the inner-city grid. On one hand, the line overloads are influenced by the current grid loading and the existing line types and cross-section area. On the other hand, the penetration of the new loads into the grids can enforce a line overload. The discrepancies in line overload in the inner-city grid, in comparison to the urban and the suburban grids, stem from the aforementioned differences in the penetration of the new loads. In addition to the demonstrated planning examples, the geographical location of the eleven chosen representative MV grids is investigated. This finding is further analysed in the 5th PG (section 5.1.5, p. 107), which concludes the expected line reinforcements for the different grid areas.

Apart from the line overloads, the planning examples did not exhibit voltage range violations due to the integration of the new loads. The execution of the line reinforcements in the years 2030 and 2040 prevented the voltage range violations to arise in the year 2050. Therefore, the conventional planning measure TVR (explained in section 3.8.3) is not applied, even though it is considered a viable planning measure. This shows that the MV grids are stable in terms of voltage, as the permissible voltage range is not violated. This finding is further analysed in the 6th PG (section 5.1.6, p. 108).

The third finding focuses on the difference between the two voltage levels. By analysing the two grid parts with V_n = 10 kV and V_n = 20 kV in the city grid, the two voltage levels exist intertwined in the same urban area. Hence, the penetration of the new loads is expected to be alike in these two grid parts. Nevertheless, line overloads are expected in the grid part with V_n = 10 kV with no grid limit violations occurring in the grid part with V_n = 20 kV. This finding is further analysed in the 7th PG (section 5.1.7, p. 109).

This finding focuses on the costs required to apply each of the PAs. Based on the occurring line overloads, several PAs are applied and their costs are calculated. An analysis of the different LM variants shows the differences between them in terms of saved line measures. Moreover, the different LM layouts demonstrate the influence of the costs of the MICT infrastructure on the total costs of LM. As for the ES, the suburban and the urban planning examples show that ES remains an expensive innovative planning technology. Further analysis of the usability of LM is presented in the 4th PG (section 5.1.4, p. 104).

The demonstrated analyses of the three presented planning examples are performed for the remaining selected representative MV grids. After analysing the grid topology and modelling the new loads into the grid, different PAs are generated to remedy the occurring grid limit violations. The results of these PAs are consolidated and analysed, so that general PGs can be deduced.

4.7 Assessment of the Planning Alternatives[18]

Based on the scenarios chosen in sections 2.1.2 and 2.2.2 and the modelling of the new loads described in sections 3.3, 3.4 and 3.5, the development of the total load power per investigated MV grid is shown in Figure 4.22. There are six bars for each MV grid, where the first three bars display the load development for the conservative scenario for the years 2030, 2040, and 2050 and the following three bars display the load development for the progressive scenario for the same years. The current conventional load is represented by the sum of the secondary substation load and the customer station load. The shown charging infrastructure load stands for all CPs in the MV grid independent of their type. The load for the HP with $P_{HP} = 3$ kW is demonstrated, whereas the load for the other two HP powers is illustrated as a delta on top. The grid structure parameters for the eleven MV grids and their corresponding grid specific values for the load development are listed in Table 8.3 (p. 155). Figure 4.22 shows that the development of the new loads correlates with the existing secondary substation loads from the transformer planning perspective. Since the integration of the EV and the HP load occurs mainly in the downstream LV grids, a MV grid that supplies predominantly residential areas (secondary substations) exhibits a larger load development than a MV grid supplying industrial areas (customer substations). This indicator becomes clear by comparing MV grids with a high share of customer substations (e.g., G04 and G11) with other MV grids which mainly supply secondary substations (such as G01 and G09). Hence, it can be generally concluded that the load development due to the integration of the EV and the HP loads is proportional to the secondary substation load.

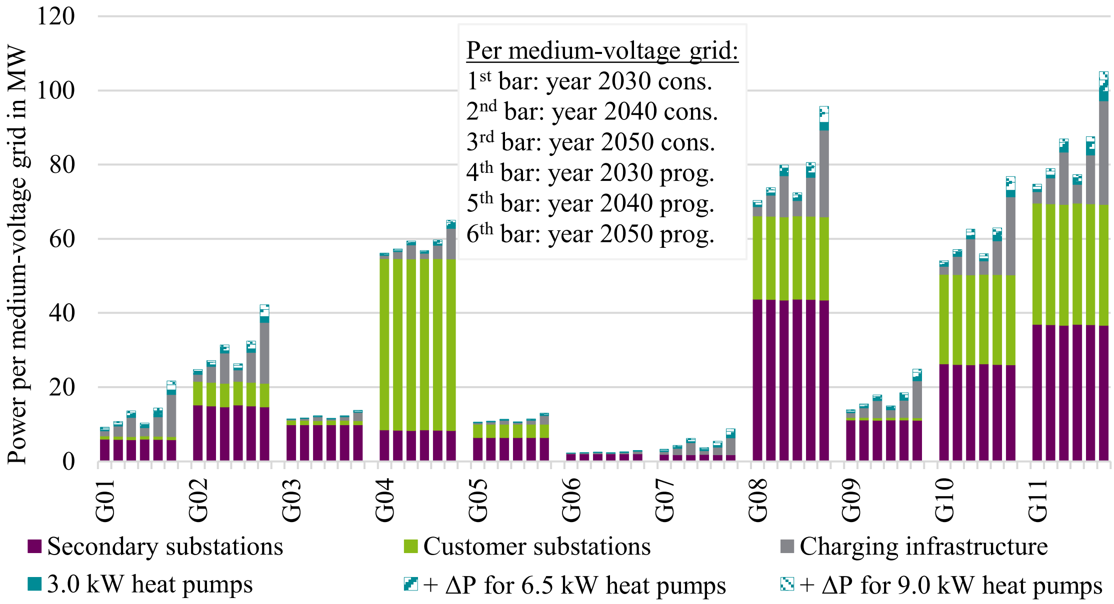

Figure 4.22: Development of the total load power per medium-voltage grid according to the years and the scenario from the transformer planning perspective based on [96]

[18] The results discussed in this section have already been published in [40] and [96].

To remedy the grid limit violations resulting from the shown load development, the conventional planning measures and the innovative planning technologies are applied. The required line measures over all investigated MV grids are consolidated per PA and shown in Figure 4.23 differentiated according to the investigation year. An analysis of the figure shows that the required line measures for the innovative PAs are less than the required line measures for the conventional PA. Thus, the innovative technologies can reduce the otherwise required conventional measures. The required line measures for the PA implementing LM-V1 do not differ between the three HP models, since HPs are shut down within the regulation done by LM-V1. The PA executing ES requires the second least total line measures followed by the PA implementing LM-V2. The PA with the innovative technology LM-V3 requires more line length than the PA with LM-V2 and nearly as much line length as the PA with the conventional planning. This relies on the limited load regulation offered by the LM-V3 in comparison to the LM-V2, as the number of puCPs to be integrated into the MV grids is fewer than the number of prCPs and ufCPs together.

In addition to the reduction in the line length accomplished by implementing the innovative technologies, these can also – to a limited extent – postpone the required line length to later investigation years. This becomes especially clear for the required line length for the progressive scenario by the conventional PA in the year 2040 in comparison to the required line length by the PAs with LM-V1 and ES for the same investigation year. However, in comparison to the required line length using conventional planning measures, implementing innovative technologies does not drastically decrease or postpone the required line measures for the investigation year 2030. This is due to the asset renewal measures in terms of replacing line sections with small cross-section areas (c < 150 mm^2) that in any case need to be performed independently from the long-term strategic grid planning.

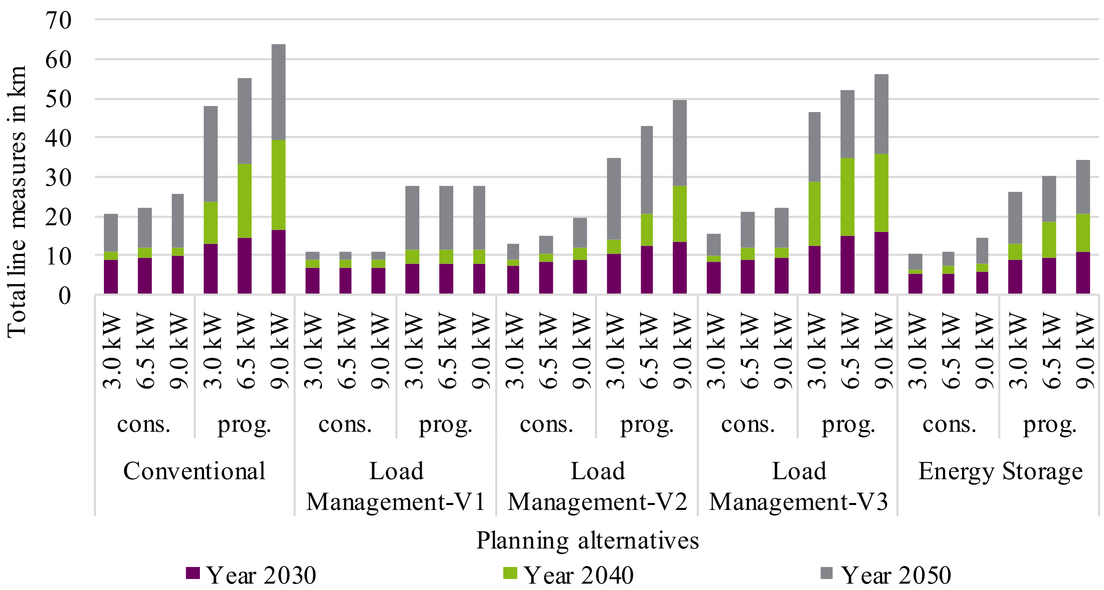

Figure 4.23: The total line measures consolidated for the conventional and the innovative planning alternatives for the eleven medium voltage grids shown according to the heat pump model, the development scenario, and the investigation year [96] (cons. = conservative, prog. = progressive)

Depending on the required measures per PA shown in Figure 4.23 and the cost calculation method presented in section 3.10.1 with the cost assumptions provided in section 8.2 (p. 153), the costs are calculated per PA and displayed in Figure 4.24. The presented costs are consolidated over all MV grids for the conventional as well as the innovative planning measures and technologies. For the LM technology, the shown layout is the (MV) layout (see Table 3.7) as it focuses on the MICT costs required in the MV level. The resulting costs are the sum of the capital expenditure costs with the operational expenditure costs by subtracting the residual value of the installed equipment.

The figure shows that the ES corresponds to the highest investment costs, making it the most expensive planning technology and subsequently the least attractive PA in terms of the economics of planning. In comparison to the reference conventional planning, the LM-V1 technology requires fewer investment costs and is, therefore, a competitive option for grid planning. The two further LM variants, namely, LM-V2 and LM-V3, correspond to nearly equal total costs in comparison to the conventional planning. Hence, the economic fitness of these two innovative technologies with respect to the conventional planning needs to be further evaluated.

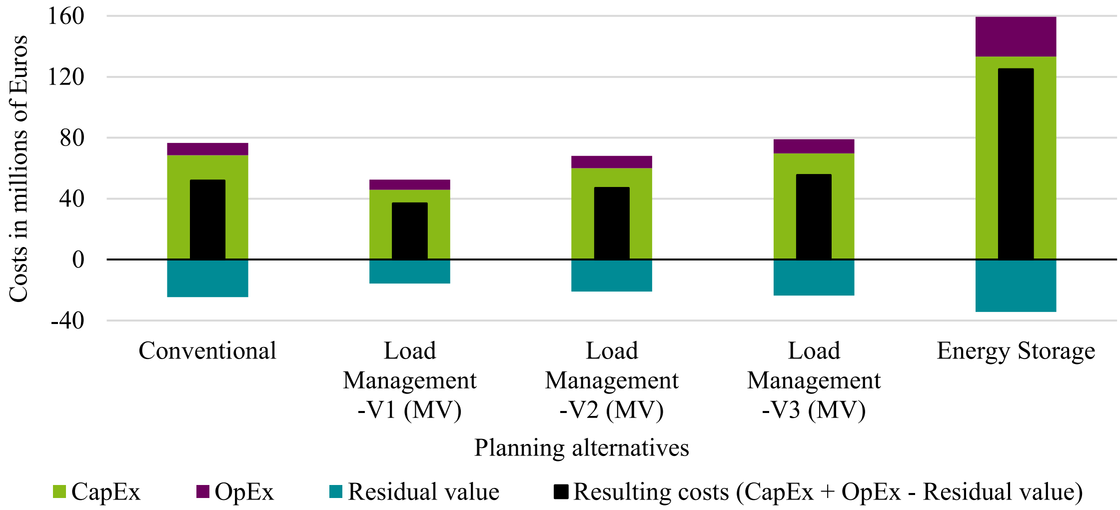

Figure 4.24: Consolidated net present value costs in millions of Euros for the generated planning alternatives over the investigated medium voltage grids based on [96] (CapEx = Capital Expenditure, OpEx = Operational Expenditure) (Net present value for the start year 2021)

A further investigation of the innovative planning technologies in comparison to the conventional planning is displayed in Figure 4.25 (p. 94). The figure shows the saving potential of each of the analysed PAs using the innovative planning technologies in comparison to the incurring costs of the same PA using the costs for the conventional planning as a basis for the comparison. Similar to the previous figure, this assessment adopts the LM layout (MV) as it solely considers the MICT costs in the MV level.

The horizontal axis in the graphic represents the investigated PAs. The formation of a PA is explained in detail in Figure 3.10. A 50 % value on the horizontal axis corresponds to half of the total PAs investigated in this work. The vertical axis in the graphic corresponds to the incurring costs of a certain PA using one of the innovative technologies in relation to the incurring costs for the same PA using conventional planning. A 50 % value on the vertical axis means that for this PA 50 % of the costs required for the conventional planning could be saved by applying the corresponding innovative technology.

Figure 4.25 shows that the innovative technology LM-V1 is more cost-effective than the conventional planning in approximately 97 % of the PAs. This percentage of PAs declines for the innovative technology LM-V2 and decreases drastically for LM-V3 which is cheaper than the conventional planning in approximately 35 % of the analysed PAs. The complete assessment of the costs for the six LM layouts for the corresponding LM variants in comparison to the conventional planning is discussed in the 4th PG (section 5.1.4, p. 104).

The ES technology is in none of the PAs more cost-effective than the conventional planning Therefore, it is not included as one of the economically practical solutions for the strategic grid planning and is not included in the PGs presented in section 5.1 (p. 95). Nevertheless, the ES technology is analysed with the further assessment criteria introduced in the alternative assessment model as it showed potential in the analysis of the previous planning examples. The results of the alternative assessment model are discussed in section 5.4.2 (p. 118).

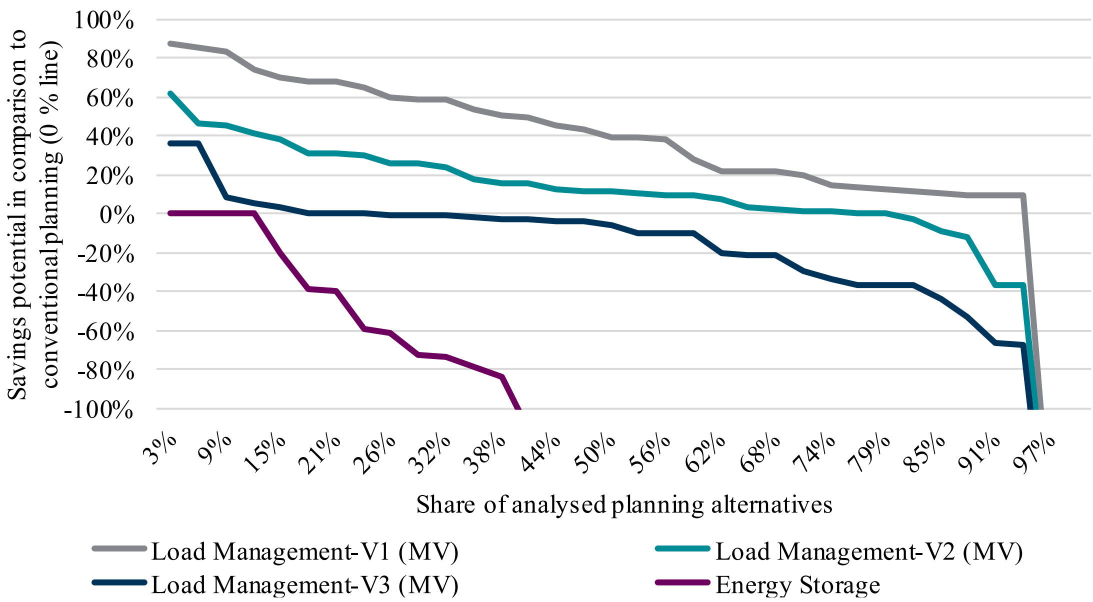

Figure 4.25: The savings potential of the innovative planning technologies in comparison to the conventional planning consolidated for all generated planning alternatives with the two scenarios, the three heat pump models and the three investigation years

Based on the presented technical and economic assessment of the PAs, the following PGs are deduced.

5 Deduction of the Planning Guidelines for Urban Medium-Voltage Grids

Based on the assessment of the applied strategic planning methodology presented in section 4.7, long-term strategic grid planning can be concluded and concretized in PGs. These PGs offer a uniform planning course of action in terms of consistent recommendations and generally valid assumptions. The PGs should be specifically tailored to the DSOs so that the same grid planning is performed uniformly within the grid area.

The newly deduced PGs either the MV PGs or the cross voltage level PGs are developed based on the general framework conditions and the development scenarios introduced in Chapter 2 as well as the methodology of the strategic planning determined in Chapter 3. These PGs can be used as a base for developing or updating the DSOs' specific PGs.

This chapter starts with introducing the seven MV PGs, which are followed by a decision path for strategic grid planning. Additionally, cross voltage level PGs are proposed that can be applied independently of the distribution voltage level. Consequently, the conditions for applying the PGs are presented and discussed. These conditions mainly refer to the restrictions of the performed grid planning and their corresponding assumptions. After concluding the PGs and their related conditions, a sensitivity analysis of the PG is conducted. Within the sensitivity analysis, a consideration of the charging hubs and the results of the alternative assessment model are introduced. These results of the alternative assessment model further investigate the PAs and offer a new perspective other than the sheer economic assessment. Finally, the methodology of the strategic grid planning is critically discussed to emphasise if there are any deficiencies in the applied methodology that need to be considered.

5.1 Planning Guidelines for Urban Medium-Voltage Grids[19]

The PGs are meant to guide the DSO through the grid planning process. The first step in the grid planning is to determine the future load requirements which are summarised in the 1st PG. Depending on the future load, grid reinforcement measures may need to be executed which are established through standardisation of the line cross-section area and the primary substation transformer size in the 2nd and the 3rd PGs, respectively. As an alternative to the conventional planning measures, the 4th PG specifies the usability of LM in terms of LM layout and LM variant. Moving to a wider perspective of the grid planning, the 5th and the 6th PGs provide an overview of the grid planning in terms of expected line reinforcements and the utilised voltage range in the MV level. The 7th PG draws attention to the difference between grids of V_n = 20 kV and grids of V_n = 10 kV.

[19] The results discussed in this section have already been published in [40] and [96].

5.1.1 1st Planning Guideline: Determination of load assumptions

"For the private charging infrastructure, a mean effective charging power of $P_{prCP,T} = [0.3;\ 2.5]$ kW and $P_{prCP,F} = [0.8;\ 2.7]$ kW are recommended per building connection for dimensioning the primary substation transformer and the feeders, respectively.

For the public charging infrastructure, a mean effective charging power of $P_{puCP,T} = [0.1;\ 0.8]$ kW and $P_{puCP,F} = [0.1;\ 0.9]$ kW are recommended per building connection for dimensioning the primary substation transformer and the feeders, respectively.

For the heat pumps, an electric power of $P_{HP,T,F} = [0.1;\ 0.5]$ kW for the heat pump with $P_{HP} = 3$ kW and a factor of [2.2; 3] for the heat pumps with $P_{HP} = 6.5$ kW and $P_{HP} = 9$ kW respectively are recommended per building connection for dimensioning both the primary substation transformer and the feeders.

For household loads, a load power of $P_{conv,T} = 2$ kW and of $P_{conv,F} = 2.4$ kW are recommended per building connection for the load calculation per secondary substation for dimensioning the primary substation transformer and the feeders, respectively."

The first step in future MV grid planning is to identify the expected load development over the period under consideration. A clear load forecast of the development helps to plan the grids in an optimal way, both technically and economically. As the considered loads are new loads with limited historical data, it is important to determine the load values for the different loads over the investigation years. The determined power values are based on the scenarios presented in Chapter 2 with the proposed modelling of the loads in terms of scaling down and distribution, as well as the power assumptions and DFs presented in Chapter 3.

As already explained in section 3.1, a distinction is made in the grid planning between the transformer planning perspective and the feeder planning perspective when calculating the DFs. Therefore, two power values are also recommended for the two planning perspectives.

Figure 5.1 (p. 97) shows an analysis of the new loads for the eleven investigated MV grids for the conservative and the progressive scenarios over all investigation years for both of the planning perspectives. The new loads include prCPs, puCPs, and HPs. The load power of ufCPs is consolidated with the power of puCPs.

While the assumed charging power for the puCPs is larger than that of the prCPs (see Table 3.1), the penetration of prCPs into the MV grids is larger than that of puCPs. This results in higher mean effective charging power for the prCPs in comparison to the mean effective charging power of the puCPs in the corresponding scenario, investigation year, and planning perspective.

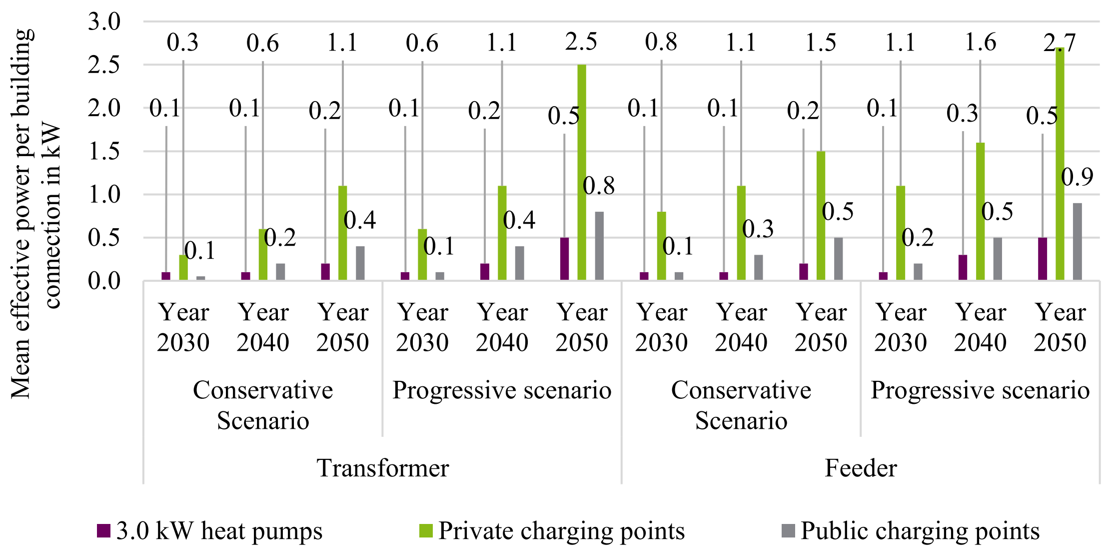

Figure 5.1: Mean effective power per building connection for heat pumps with P_{HP} = 3 kW, private and public charging points according to the year, the scenario, and the planning perspective

Figure 5.1 shows that, for dimensioning the primary substation transformer, the mean effective charging power for the prCPs of $P_{prCP,T}$ = [0.3; 2.5] kW per building connection increases from the conservative scenario in the year 2030 to the progressive scenario in the year 2050. In comparison, the mean effective charging power for the puCPs increases relatively less with $P_{puCP,T}$ = [0.1; 0.8] kW in the conservative scenario in the year 2030 to the progressive scenario in the year 2050 for the same planning perspective.

By comparing the mean effective charging power of the two planning perspectives, higher mean effective charging power values can be assumed for the feeder planning perspective, as shown in Figure 5.1. From the transformer planning perspective, the DF "$DF_{P_{eff},\Sigma n_{CP}}$", which corresponds to the total number of CPs in the MV grid Σn_{CP} for the effective charging power over all CPs in the grid P_{eff}, is used in modelling the CP load $P_{load,CP}$ according to equation (5.1).

Whereas from the feeder planning perspective, the DF "$DF_{P_{eff,F},n_{CP,F}}$", which corresponds to the number of CPs in the feeder $n_{CP,F}$ and the effective charging power over the CPs in the feeder $P_{eff,F}$, is used in modelling the CP load $P_{load,CP,F}$ according to equation (5.2).

Obviously, the number of CPs in the MV grid Σn_{CP} is higher than the number of CPs in a single feeder $n_{CP,F}$ and as Figure 3.4 shows that the DF decreases with an increasing number of CPs. Moreover, the distribution of the CPs of different charging powers remains homogenous over all the feeders in the MV grid, as the assumed distribution of charging powers (see Table 3.1) remains constant for all the CPs in the MV grid.

Hence, the $DF_{P_{eff},\Sigma n_{CP}}$ is lower than the $DF_{P_{eff,F},n_{CP,F}}$ as shown in equation (5.3). Therefore, the modelled CP load from the transformer perspective is lower than the modelled CP load from the feeder perspective (equation (5.4)), which results in higher DFs and higher load power values in comparison to the transformer planning perspective.

$$P_{\mathrm{load,CP}} = P_{\mathrm{CPi}} \cdot DF_{\mathrm{P_{eff}},\Sigma \mathrm{n_{CP}}} \tag{5.1}$$

$$P_{\mathrm{load,CP,F}} = P_{\mathrm{CPi}} \cdot DF_{\mathrm{P_{eff,F}},\mathrm{n_{CP,F}}} \tag{5.2}$$

$$DF_{\mathrm{P_{eff}},\Sigma \mathrm{n_{CP}}} < DF_{\mathrm{P_{eff,F}},\mathrm{n_{CP,F}}} \tag{5.3}$$

$$P_{\mathrm{load,CP}} < P_{\mathrm{load,CP,F}} \tag{5.4}$$

With an increasing number of CPs in the grid (progressive scenario 2050), the difference in the DFs between the transformer perspective and the feeder perspective decreases as the DFs reach a nearly constant value for an increasing number of CPs (see Figure 3.4). Therefore, the delta in the mean effective charging power between the two perspectives in the year 2050 for the progressive scenario is much smaller than the delta between the two perspectives in the year 2030 for the conservative scenario.

By analysing the increase in power values for the prCPs shown in Figure 5.1, it can be deduced that the power from the transformer perspective quadruples from the year 2030 to the year 2050, while the power value from the feeder perspective doubles in the same period. This may result that the line measures can be required in the earlier years (until the year 2040) while the transformer measures will become necessary in later years (starting from the year 2040).

Furthermore, Figure 5.1 shows the power values for HPs with P_{HP} = 3 kW for the transformer planning perspective and the feeder planning perspective. The power values exhibit a value range of $P_{\mathrm{HP,T,F}}$ = [0.1; 0.5] kW in the year 2030 for the conservative scenario to the progressive scenario in the year 2050 per building connection. For the HPs with P_{HP} = 6.5 kW and P_{HP} = 9 kW, the power values for the HPs with P_{HP} = 3 kW can be multiplied with a factor ranging between [2.2; 3]. In contrast to the CPs, there is no significant difference here between the transformer planning perspective and the feeder planning perspective, as the DFs for HPs reach a nearly constant value starting from around 150 HPs (see Figure 3.5).

The power values of the prCPs, the puCPs, and the HPs from both the transformer planning perspective and the feeder planning perspective are given in Table 5.1 (p. 100).

Once the number of CPs for a given MV grid area is available, Figure 5.2 (p. 99) can be used to calculate the power value per prCP or puCP from the feeder planning perspective. The figure shows the mean value of the power per CP for the two development scenarios and the three investigation years. The power values of ufCPs are consolidated with the power values of the puCPs as, together, they represent the public charging infrastructure.

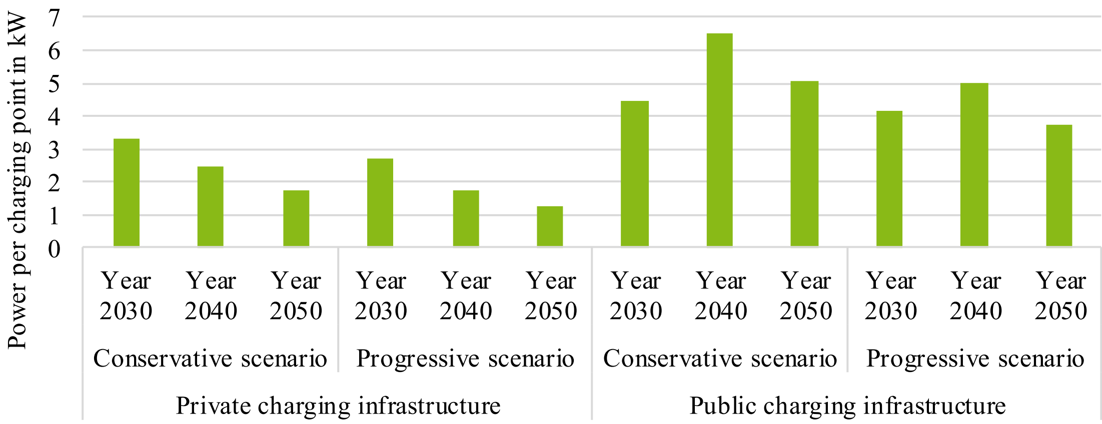

Figure 5.2: Power per charging point for private and public charging points according to the year and the scenario from the feeder planning perspective

The figure shows that the mean power values per prCP decrease with an increasing number of prCPs (the development from the year 2030 to 2050), as the DFs for CPs decrease strongly with an increasing number of CPs. On the other hand, the mean power values of puCPs exhibit a slight increase from the year 2030 to the year 2040, as the assumed distribution of charging power increases for the higher charging powers P_{CP} = 50 kW and P_{CP} = 150 kW (see Table 3.1). From the year 2040 to the year 2050, the mean power values for puCPs decrease similar to the mean power values of the prCPs. The power values per prCP as well as per puCP from the transformer planning perspective are given in Table 5.1 (p. 100).

As for household loads, Figure 5.3 shows the mean value of the household load per building connection in relation to the number of building connections per secondary substation from the transformer planning perspective over the three investigation years.

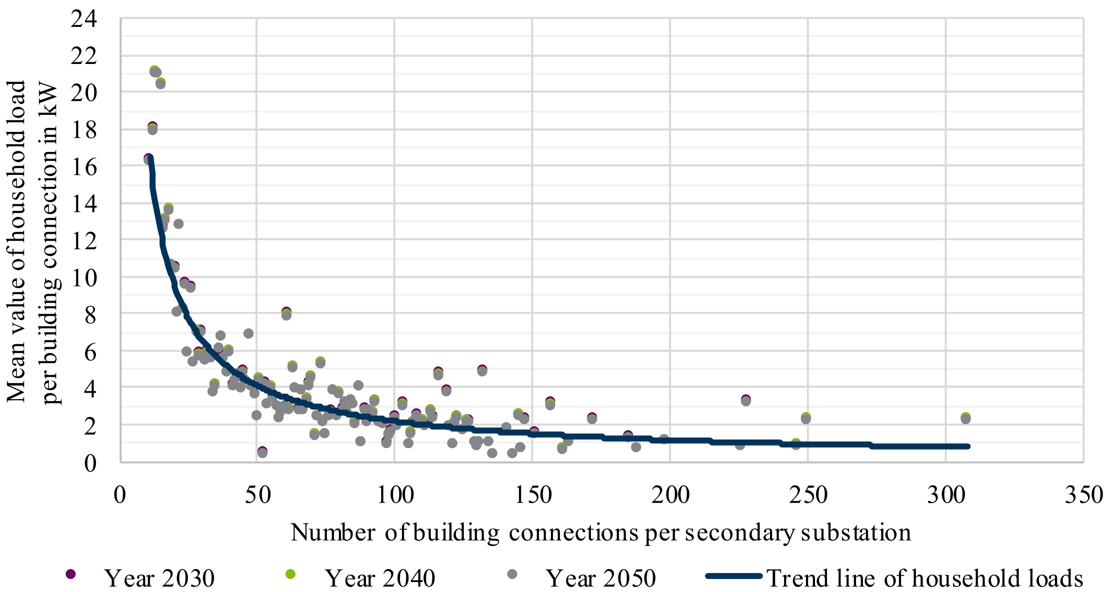

Figure 5.3: Mean value of the household load per building connection for each secondary substation from the transformer planning perspective

The power values of the three investigation years overlap, as the change in household load over these years is negligible, as already described in section 3.3. Additionally, the figure shows the trend line of household loads in relation to the number of building connections per secondary substation. The trend line shows that the household load for a large number of building connections (≅300) per secondary substation decreases down to approx. $P_{\mathrm{load}} = 1$ kW.

As the majority of the secondary substations supply between 50 and 150 building connections, the load power value assumption for household loads for the secondary substations from the transformer planning perspective is $P_{\mathrm{conv,T}} = 2$ kW per building connection. For the feeder planning perspective, the factor of 1/0.85 (according to equation (3.8) in section 3.3) can be calculated for the household loads to determine their load power value from the transformer planning perspective. As explained in section 3.3, this factor relates the household load power value from the two planning perspectives. Applying it corresponds to a load power value of average $P_{\mathrm{conv,F}} = 2.4$ kW per building connection from the transformer planning perspective. In contrast, the commercial loads in the LV level and the MV level are heterogeneous, which is why no generally valid power value assumptions are derived for them.

Table 5.1 (p. 100) provides a summary of the power value assumptions for the new loads and the household loads with a differentiation between the transformer planning perspective and the feeder planning perspective. Additionally, the provided power value assumptions are differentiated for the CPs between the value per building connection and the value per CP.

Table 5.1: Summary of the power value assumptions for the different load types and planning perspectives

Load type	**Transformer**		**Feeder**	
	Power in [kW] per		**Power in [kW] per**	
	Building connection	**Charging point**	**Building connection**	**Charging point**
Private charging points	[0.3[1]; 2.5[2]]	1.0	[0.8[1]; 2.7[2]]	[3.3[1]; 1.3[2]]
Public charging points	[0.1[1]; 0.8[2]]	0.3	[0.1[1]; 0.9[2]]	[4.5[1]; 3.7[2]]
Household per secondary substation	2.0	-	2.4	-
Heat pump model 1	[0.1[1]; 0 .5[2]]		[0.1[1]; 0 .5[2]]	
Heat pump models 2 and 3	[2.2; 3]		[2.2; 3]	

[1] Value for the conservative scenario in the year 2030
[2] Value for the progressive scenario in the year 2050

5.1.2 2nd Planning Guideline: Standardisation of line cross-section area

> ***"For 10 kV grids, the present standard cable cross-section areas of c = 150 mm² (Al) or c = 185 mm² (Al) can be maintained. An upgrade with a further standard cable cross-section area of c = 300 mm² (Al) is recommended."***

After modelling the loads according to the aforementioned power value assumptions, the grid planning begins with an essential planning measure which is the line measure. Referring to the line measures described in section 3.8.1, the line measures for the investigated MV grids are carried out with the four line cross-sections areas $c = 150\ \mathrm{mm}^2$, $c = 185\ \mathrm{mm}^2$, $c = 240\ \mathrm{mm}^2$ and $c = 300\ \mathrm{mm}^2$ (in each case: Aluminium (Al) with nominal voltage $V_\mathrm{n} = 10\ \mathrm{kV}$ and cable type NA2XS2Y). The lines are laid down either single or in parallel[20] in the same route, depending on the power to be transmitted.

In the context of this PG, the term "cross-section area" applies to MV lines with an aluminium conductor and a nominal voltage $V_\mathrm{n} = 10\ \mathrm{kV}$. Figure 5.4 (p. 102) shows the share of line length per line cross-section area to the total line measures performed across the investigated MV grids with $V_\mathrm{n} = 10\ \mathrm{kV}$. Two planning techniques are executed, namely, "planning including line reinforcement and/or replacement" and "planning with exclusively line replacement".

In the planning technique "planning with line reinforcement and/or replacement", the line measures are executed according to the method described in section 3.8.1. Within this technique, a line reinforcement is performed when the existing overloaded line has a polyethylene insulation material (e.g., NA2XS2Y) or a cross-section area $c \geq 120\ \mathrm{mm}^2$. As for the line replacement, it is performed when the existing overloaded line has a cross-section area $c < 120\ \mathrm{mm}^2$ or an oil or paper insulation material (e.g., NAKBA).

On the other hand, the planning technique "planning with exclusively line replacement" enforces a direct replacement of the existing overloaded lines without considering the existing line insulation material or the cross-section area.

The planning technique "planning with line reinforcement and/or replacement" is in line with the focus of DSOs on grid reinforcement and upgrading measures done in combination with the asset management strategy. Compared to the grid reinforcement, the planning technique "planning with exclusively line replacement" represents the grid expansion measures done by DSOs to connect new loads into the grid or to construct new feeders. The combination of these two planning techniques represents the line measures done by the DSOs.

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[20] Reduction factors are neglected in the case of parallel lines, since the investigated peak load operating point is to be regarded as a short-term operating point. In addition, the newly constructed parallel lines are not fully thermally loaded and are routed at a sufficient distance from each other.

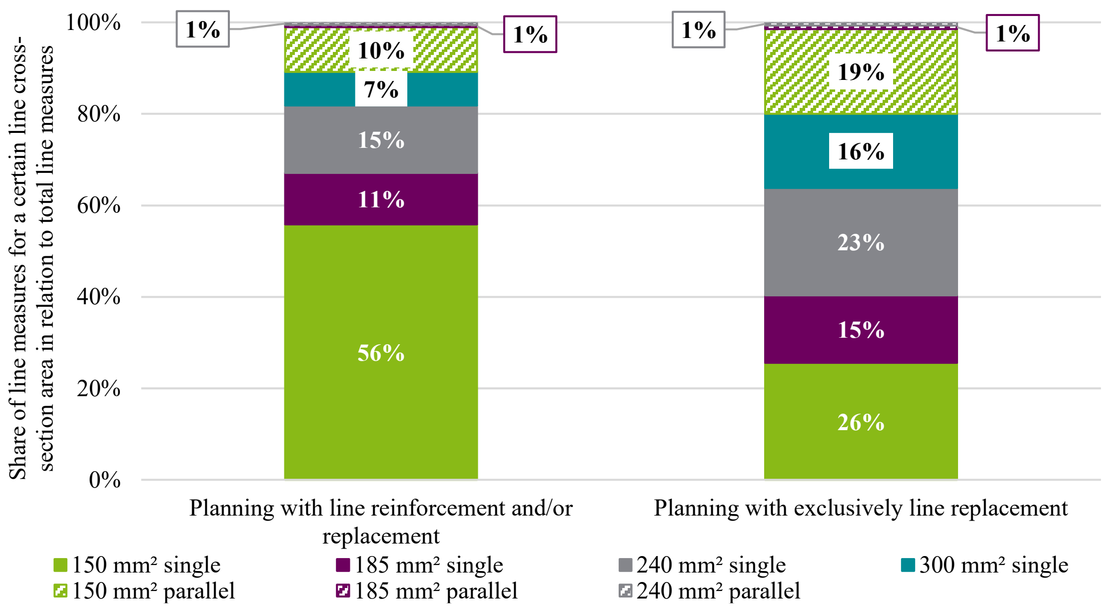

Figure 5.4: Share of line measures of different line cross-section areas with an aluminium conductor in relation to total executed line measures for the two planning techniques in the medium-voltage grids with $V_n = 10$ kV [96]

For the planning technique “planning with line reinforcement and/or replacement”, the results show that approximately two-thirds of all line measures can be executed with the cross-section area $c = 150$ mm^2, followed by $c = 185$ mm^2. Therefore, the two current standard cable cross-sections $c = 150$ mm^2 and $c = 185$ mm^2 can still be recommended.

For considering the grid expansion measures (and not only the grid reinforcement), the planning technique “planning with exclusively line replacement” is also analysed in Figure 5.4. By analysing the share of the line measures for the different line cross-section areas, it can be deduced that the cross-section areas $c = 150$ mm^2 and $c = 185$ mm^2 are still effective and represent one-third of all the line measures. However, they are not sufficient in the majority of the line measures where bigger cross-section areas are required. Therefore, $c = 300$ mm^2 is recommended as a second standard line cross-section area, which in turn also suffices for the line cross-section area $c = 240$ mm^2, if line sections, such as the MV feeders, are heavily loaded.

To perform line measures (see section 3.8.1), it is recommended to first lay the cross-section areas $c = 150$ mm^2 and $c = 185$ mm^2, as other specifications (such as the changing short-circuit currents due to the changing line impedances) must be considered for bigger cross-section areas. If the supplied load exceeds the maximum ampacity of the cross-section areas $c = 150$ mm^2 and $c = 185$ mm^2, the cross-section area $c = 300$ mm^2 is recommended. Additionally, laying several parallel lines is to be avoided to reduce both the operating costs incurred and to simplify the operational management. If the ampacity of the cross-section area c = 300 mm^2 is not sufficient, the cross-section areas $c = 150$ mm^2 and $c = 185$ mm^2 can be laid in parallel. It must be noted that no line measures are required in the MV grids with $V_n = 20$ kV. Therefore, a deduction of the standard line cross-section area cannot be made.

5.1.3 3rd Planning Guideline: Standardisation of primary substation transformer capacity

"The dimensioning of primary substation transformers has to follow the load assumptions from the first planning guideline, as a standard transformer size cannot be deduced due to the heterogeneous load development per substation grid area."

Continuing with standardising the dimensions of the conventional measures, the load development per MV grid is analysed in this PG. Referring to the load development shown in Figure 4.22, it is clear that the load development differs significantly between the MV grids. This difference is due to the diverse MV grid areas, which are of different sizes, have different degrees of penetration of the new loads, supply different downstream LV grids and have different grid parameters in terms of connection and load density. Figure 5.5 shows the development of the load power due to the new loads for the analysed MV grids for the two development scenarios and the three investigation years

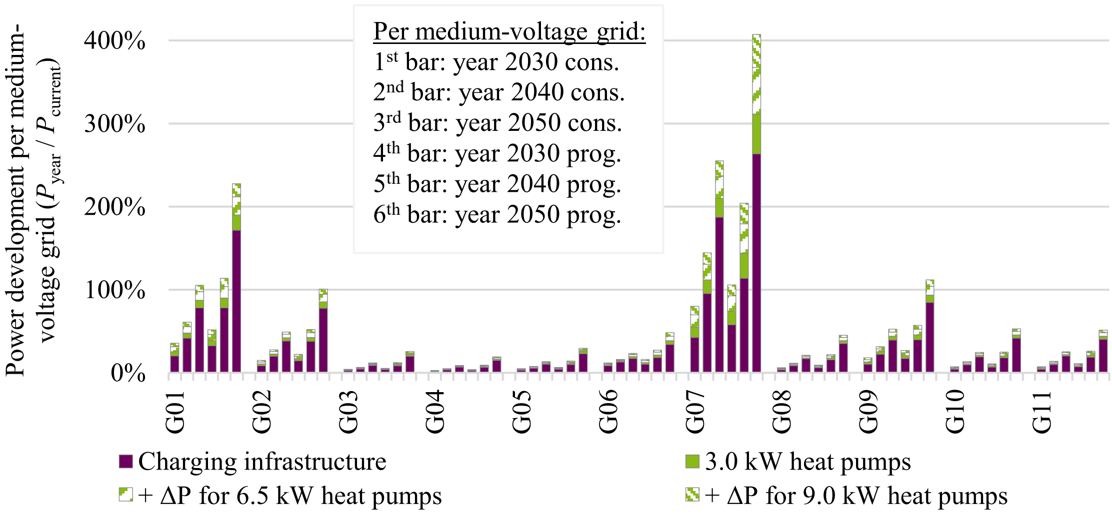

Figure 5.5: Apparent power development of charging infrastructure and heat pumps in relation to the current apparent load power according to the year and scenario

The figure displays the relative load development for the two scenarios and the three investigation years with a differentiation between the CPs and the three HP models. It is clear that the relative load development is heterogeneous according to the specific MV grid. This heterogeneous load development, from one MV grid area to another, results in uneven development of the loading of the primary substation transformers. Figure 5.6 (p. 104)[21] shows the loading of the primary substation transformers in nine MV grids in the year 2050 for the conservative scenario as well as the progressive scenario.

[21] The loading of the primary substation transformers in the grid G06 and G07 could not be determined as the data of the transformer was not available. Nevertheless, the deduced PG remains valid as the analysis of the other nine MV grids shows the same deduced conclusion.

The figure shows that the installed transformer capacity differs significantly from a MV grid to another, which in combination with the heterogeneous load development does not show a clear tendency for a certain transformer size.

If the transformer loading exceeds its loading limit as identified in section 3.7.2 and transformer measures become necessary, which according to Figure 5.6 is the case in several cases due to increasing transformer loading, the transformer measures can be carried out as explained in detail in section 3.8.2. Based on the presented methods for modelling the load development in Chapter 2 and Chapter 3 as well as the load assumptions provided in the 1st PG (section 5.1.1), it is recommended to analyse the load development of the MV grid and the resulting transformer loading individually to determine the most suitable transformer rated apparent power.

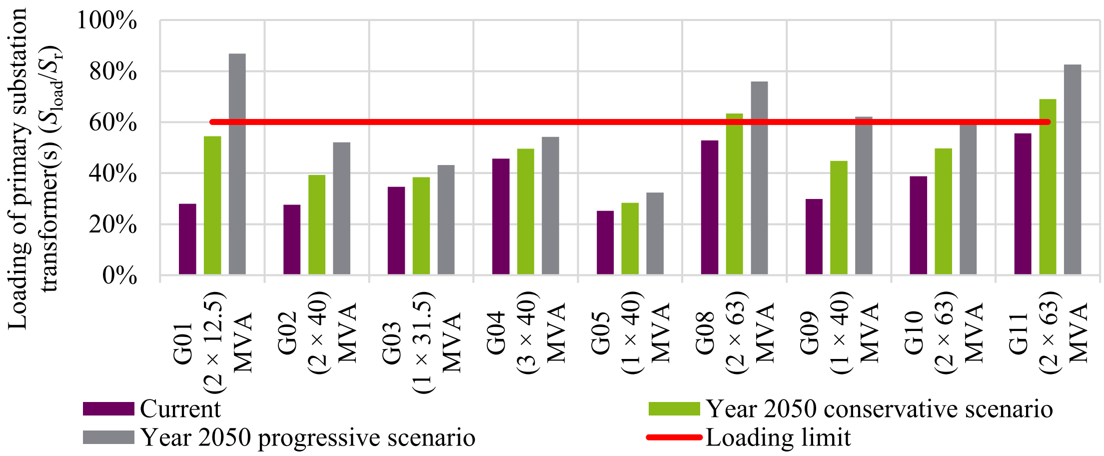

Figure 5.6: Loading of primary substation transformers for nine medium voltage grids in the year 2050 for the conservative and the progressive scenario

5.1.4 4th Planning Guideline: Usability of load management

> ***"When the measurement, information, and communication technology in the medium voltage and the low voltage grids must be fully established, the conventional grid expansion is in most cases less expensive than a load management system and is recommended. If the measurement, information, and communication technology is already available and can be used by the load management system, then the load management system becomes significantly cost efficient and is recommended."***

Moving on to the innovative technologies, LM has the potential to ensure the integration of new loads in the grids in an economically optimal way in the upcoming years. As shown in Figure 4.23, LM can reduce and delay the necessary line measures. Moreover, Figure 4.24 shows that, according to the adopted LM variant, LM can reduce the necessary costs in comparison to the conventional planning measures. As already mentioned in section 3.9.2, LM requires a MICT infrastructure to determine the grid status and regulate the loads accordingly.

A cost calculation of the possible combinations between the six LM layouts and the LM variants (described in section 3.9.2) is presented in Figure 5.7. The costs of the LM are illustrated in comparison to the required costs for the conventional planning. These shown costs are consolidated over all investigated MV grids for the two development scenarios and the three HP models (basically for all the PAs). The LM layouts are arranged in the order from left to right from the layout (MV+LV) that requires the most rollout of MICT infrastructure to the layout (0) that requires the least rollout of MICT infrastructure.

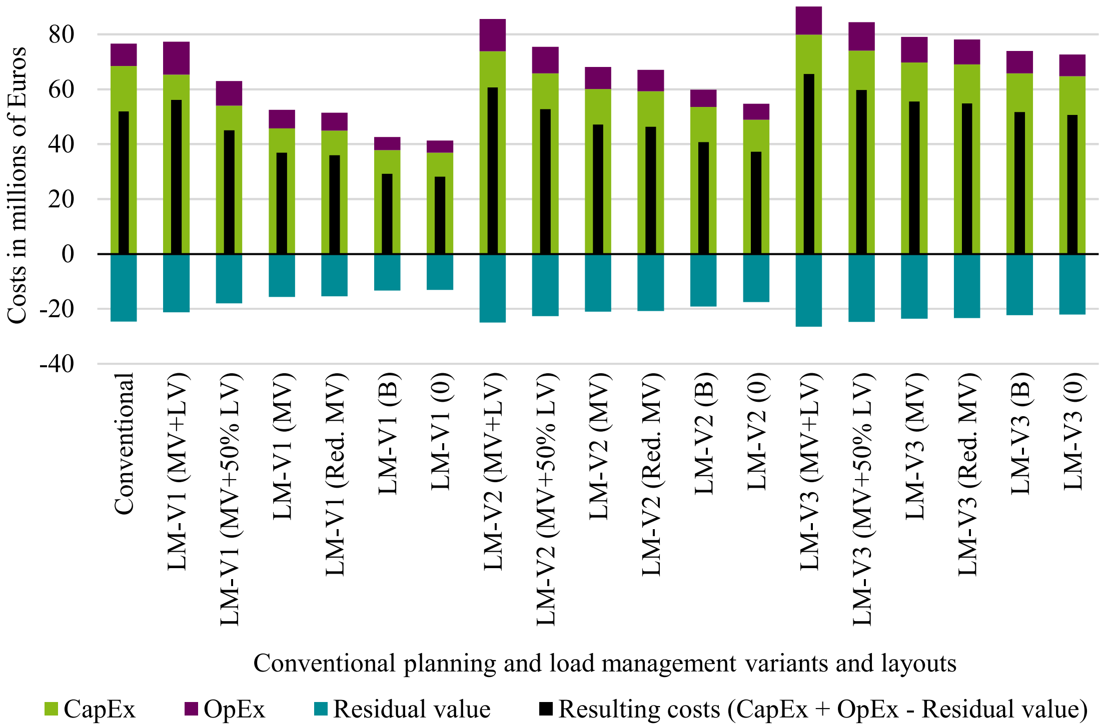

Figure 5.7: Consolidated net present value costs over the investigated medium voltage grids for the three load management variants and the six layouts in comparison to the conventional planning (LM = load management, V = variant) (Net present value for the start year 2021)

Obviously, the figure shows that for the same LM variant, the LM layout that requires a limited rollout of MICT infrastructure is more cost economic than the LM layout that requires a grid-wide rollout of MICT infrastructure. Among the three LM variants, LM-V3 exhibits the highest costs followed by LM-V2 and then LM-V1. Focusing on LM-V1, the presented costs show that all the LM layouts (apart from the LM layout (MV+LV)) are more cost economic than the conventional planning. Moving on to LM-V2, the conventional planning becomes more cost economic than the LM layouts (MV+LV) and (MV+50 % LV). The economic competitiveness of the LM in comparison to the conventional planning further decreases by considering LM-V3. Additionally, the savings potential for the three LM variants and the six layouts compared to conventional planning can be seen in Figure 5.8 (p. 106) per PA. In contrast to the previous figure of the consolidated net present value costs, Figure 5.8 illustrates the savings potential which is the net present value cost of a certain PA applying a certain LM variant and layout in comparison to the net present value cost of the same PA that applies conventional planning measures.

The figure shows that, depending on the required MICT, the cost saving potential of LM increases significantly compared to conventional planning. The figure also shows that for the LM layout (MV+LV), conventional planning is in most cases more cost-effective than the use of LM. On the other hand, LM is always significantly more cost-effective than conventional planning when MICT is already available (LM layout (0)).

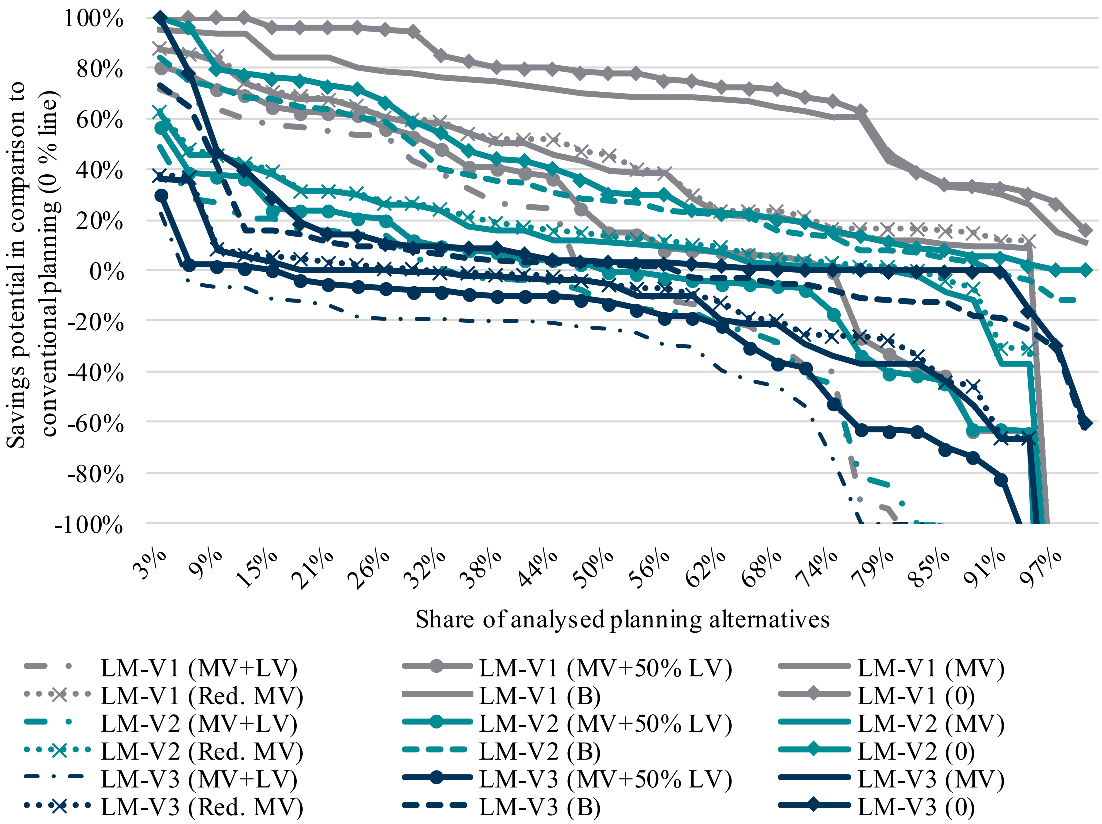

Figure 5.8: The savings potential for the three load management variants with the six layouts in comparison to conventional planning for the analysed planning variants (LM = load management, V = variant)

Each of the three applied LM variants leads to a different result in terms of necessary line measures and, consequently, the resulting cost saving potential as shown in Figure 5.7 and Figure 5.8. With a comparison of the three LM variants, it can be generally recommended to start the load regulation by regulating the charging power of prCPs according to the grid situation. After that, the HPs can be turned off by means of intelligent turn-off times, when possible. Furthermore, Figure 5.8 proves that LM-V3 offers the least advantage since the share of the prCPs clearly predominates the share of puCPs.

Comparing the cost saving potential of LM in the MV level to the cost saving potential in the LV level [134], the results show that the LM on the MV level is more cost-effective than on the LV level. This is generally because the conventional planning measures in the MV level are significantly more expensive than the costs for MICT. However, in the LV level, this cost difference is significantly smaller, as the equipment costs less than in the MV level.

5.1.5 5th Planning Guideline: Expected line reinforcement for different urban areas

> ***"Using conventional planning measures for 10 kV grids, cable reinforcements of around 20 % in suburban grids, 10 % in city grids and less than 10 % in inner-city grids are expected in relation to the total cable length of the grid."***

According to the scaling down and distribution process explained in sections 3.4.1 and 3.5.1, the integration of the new loads in the different urban areas can be roughly predicted. It is expected that the integration of the new loads mostly occurs in the suburban areas and decreases towards the inner-city centres. Hence, the most grid expansion measures can be expected in suburban MV grids due to prCPs and HPs. Figure 5.9 shows the share of the necessary line measures to the total line length in the grid for the conventional planning in the year 2050. The share of line measures to the total line length for the suburban grids G01 and G02 is approximately 20 %. This share decreases to approximately 10 % for the city grids G09, G10 and G11. For the inner-city grids G03, G05 and G08, this share decreases further. Generally, the share of the line measures depends on the current line loading. In the case of a higher or lower line loading, different shares of line measures may result. Generally, it is recommended to execute a grid planning with a variable grid concept in connection with various parameters, such as condition assessment, renewal and asset management of the lines, their existing loading, and the consideration of LM (if the MICT infrastructure is available at the LV level). It must be noted that the suburban grid G04 and the grid parts in the grids G08, G10 and G11 with a nominal voltage V_n = 20 kV do not exhibit line overloads. Hence, no line measures are expected. This is explained in more detail under the 7th PG in section 5.1.7 (p. 109). Furthermore, the MV grids G06 and G07 do not constitute a complete MV grid area and are, therefore, faded out in this evaluation. Nevertheless, each of the MV clusters is already represented by at least one of the analysed MV grids on which the deduced results can be projected.

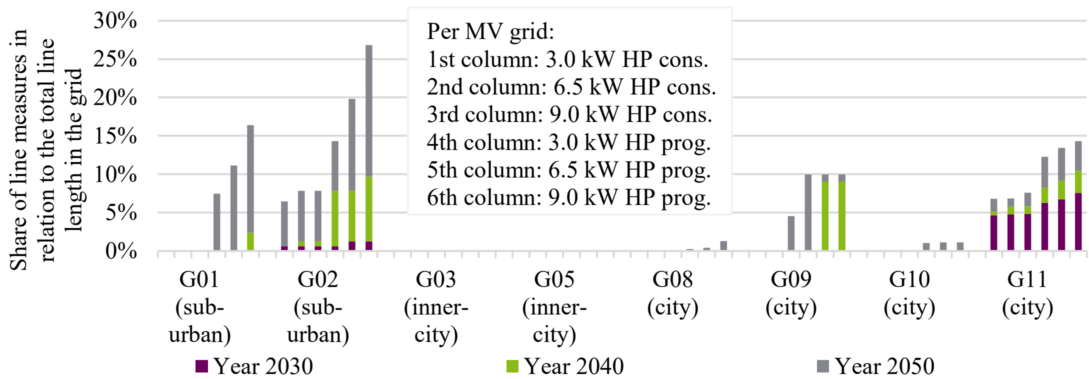

Figure 5.9: Share of the length of required line measures in comparison to the total line length per analysed medium-voltage grid in the year 2050 according to the heat pump model and the scenario (HP = heat pump, cons. = conservative, prog. = progressive)

5.1.6 6th Planning Guideline: Review of the assigned voltage range

> ***"The allowed voltage range in the medium voltage grids is not fully utilised in most cases. Therefore, it is recommended to check the voltage range division between medium and low voltage grids in the grid planning and to modify it, if necessary."***

In addition to line overloads, the integration of the new loads increases the voltage drop in the MV grids over the upcoming years. In contrast to the assumed permissible voltage range for the MV level (see section 3.7.1), the actual required permissible voltage range in the MV level is analysed. Figure 5.10 shows the minimum node voltage per investigated MV grid before and after executing the conventional planning measures. The results focus on the year 2050 while considering the least load development (conservative scenario and HP of $P_{\mathrm{HP}} = 3.0$ kW) and the most load development (progressive scenario and HP of $P_{\mathrm{HP}} = 9.0$ kW). It is noted that the minimum node voltage remains constant for the grids (G03, G04, G05 and G06) as no planning measures are required in these grids as a result of the load development. Based on these results, the maximum "voltage saving", which is the remaining voltage change in the permissible voltage range, can be calculated. Firstly, the figure shows that voltage limit violations are unexpected in any of the grids, except for G07 where the voltage limit violation is remedied by solely remedying the line overloads in the grid. Secondly, it shows that the permissible voltage change in the MV level $\Delta V/V_{\mathrm{n}} = 4.0$ % is not required in all grids. An average voltage drop of $\Delta V/V_{\mathrm{n}} \cong 2.5$ % is expected over the eleven investigated MV grids in the year 2050 with the progressive scenario and HP of $P_{\mathrm{HP}} = 9.0$ kW. Therefore, it is recommended to reconsider the permissible voltage ranges for the MV and the LV levels depending on the expected load increase and the investigation year. For the grid areas in which a limited load increase is expected, a smaller permissible voltage range can be assumed in the MV grid planning. In contrast, in grid areas where a high load development is expected, the permissible voltage range can be adjusted flexibly depending on the investigation year.

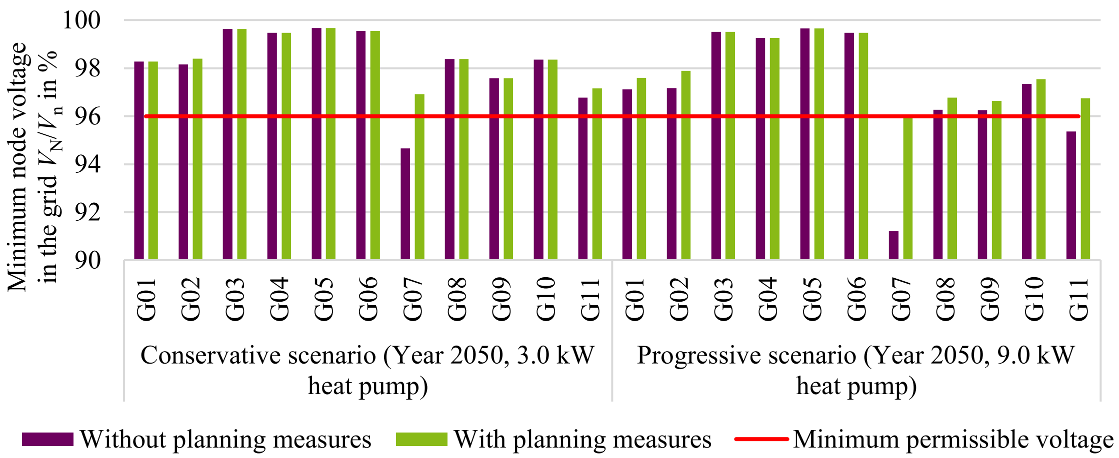

Figure 5.10: Minimum node voltage per investigated medium-voltage grids with and without planning measures in the year 2050 for the conservative scenarios and the progressive scenario with a heat pump of $P_{\mathrm{HP}} = 3.0$ kW and $P_{\mathrm{HP}} = 9.0$ kW, respectively.

5.1.7 7th Planning Guideline: 20 kV vs. 10 kV grids

"Grid reinforcements are hardly expected in 20 kV grids, as they are significantly steady for the integration of new loads in comparison to 10 kV grids."

According to the chosen clustering parameters, no difference in the clustering is identified between the grids with V_n = 10 kV and the grids with V_n = 20 kV (see section 4.1.2). Nevertheless, a difference in the loading of the grid and the resulting line overloads is discovered. Since grids with V_n = 20 kV can transmit more power per line, the increase in the line loading due to the integration of the new loads in relation to the present line loading is smaller in the MV grids with V_n = 20 kV in comparison to the increase in the line loading in grids with V_n = 10 kV. By assuming a similar grid dimension independent of the voltage level, the share of overloaded line sections in relation to the total line length can be significantly higher for grids with V_n = 10 kV than for grids with V_n = 20 kV.

Figure 5.11 shows the share of the length of the overloaded line sections to the total line length per analysed MV grid for the HP P_{HP} = 9 kW with differentiation according to the investigation year and the scenario. By analysing the suburban MV grids G01, G02 and G04, it is clear that the grids G01 and G02 with V_n = 10 kV exhibit line overloads in comparison to the grid G04 with V_n = 20 kV.

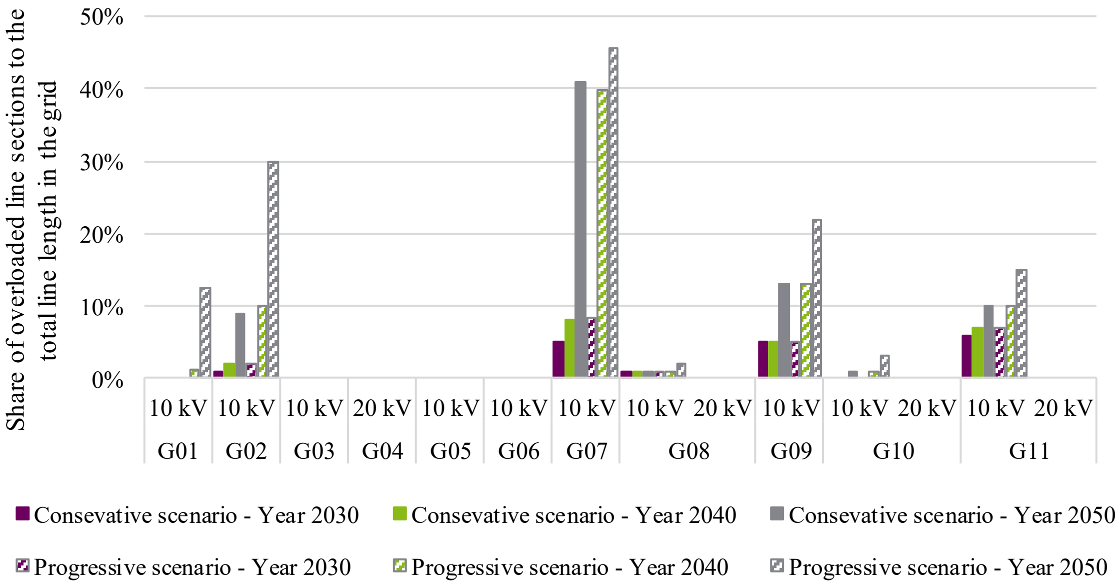

Figure 5.11: Share of the length of overloaded line sections to the total line length per analysed medium-voltage grids for the heat pump with P_{HP} = 9 kW according to the investigation year and the scenario

Further analysis is done for the grids G08, G10 and G11, where MV grids of both voltage levels are supplied from the same primary substation and exist in the same urban area. As described in sections 3.4.1 and 3.5.1, the integration of the new loads depends on the building structure and varies from one urban area to another.

Hence, it can be assumed here that the integration of the new loads in the MV grids G08, G10 and G11 is similar in the grid areas of both voltage levels. However, the overloaded line sections arise exclusively in the level $V_n = 10$ kV. Therefore, it can be stated that reinforcement measures in substation areas with both voltage levels are to be expected in grids with $V_n = 10$ kV, whereas hardly any reinforcement measures are necessary for grids with $V_n = 20$ kV.

5.2 Decision Path for Medium-Voltage Grid Planning

The aforementioned PGs offer clear recommendations regarding the strategic grid planning of MV grids. To summarise these PGs in a step-by-step guide through the strategic planning process, following Figure 5.12 summarises the aforementioned MV PGs in a flowchart.

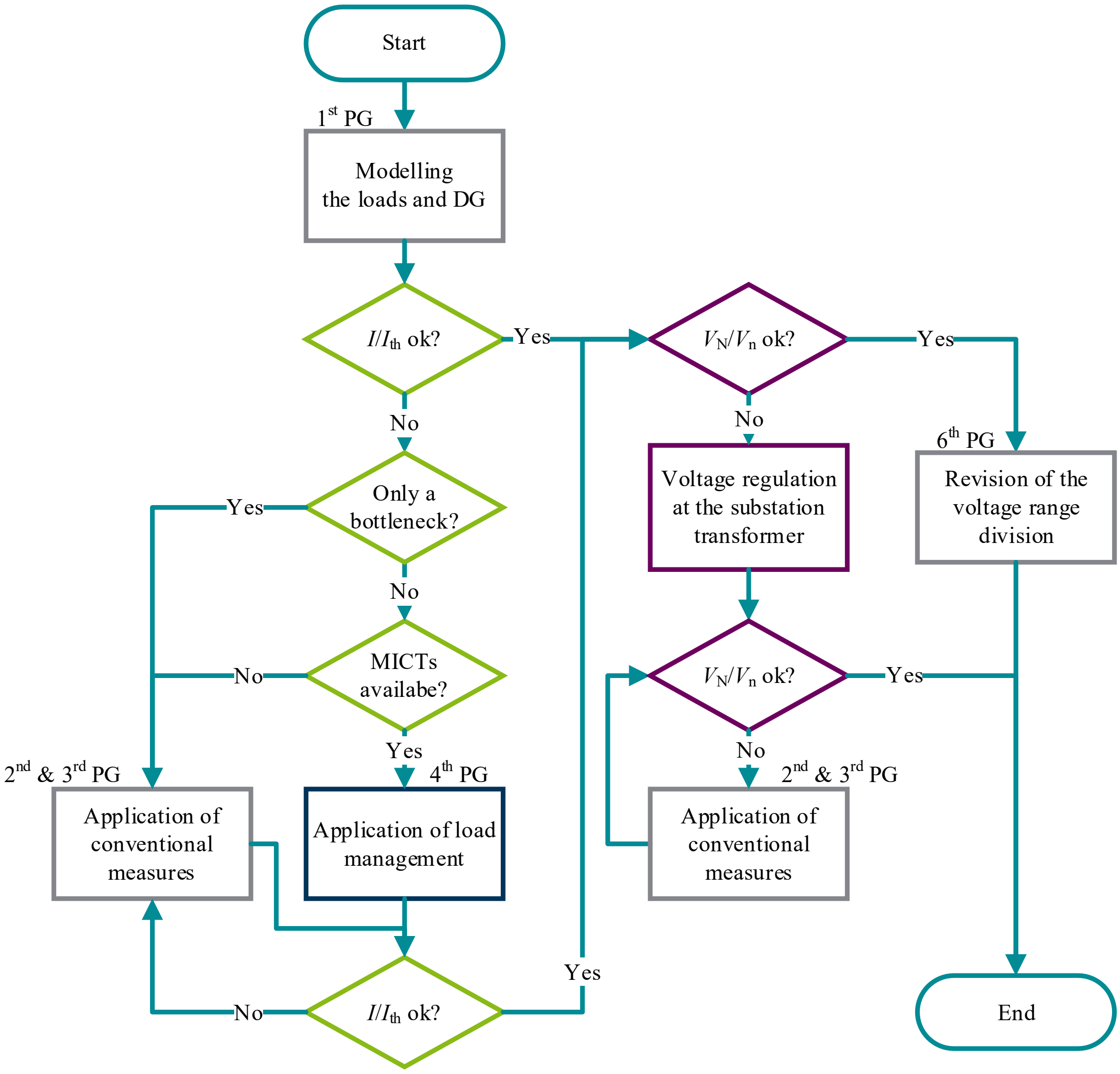

Figure 5.12: Flowchart for strategic planning of medium voltage grids [96] (DG = Distributed generation, MICT = Measurement, Information and Communication Technology)

The flowchart starts by defining the future grid supply task by modelling the loads and the DG. For the new and the conventional loads, it is recommended to apply the power assumption values given in the 1st PG (section 5.1.1). In case different development scenarios are foreseen for the specific MV grid, the modelling of the EV load and the HP load explained in section 3.4 and section 3.5, respectively, should be executed. As for the DG, the modelling of PV systems explained in section 3.6 should be applied.

After modelling the future grid supply task, the permissible grid limits have to be checked. The loading of all equipment in the MV grid is to be checked according to the permissible loading limits presented in section 3.7.2, if the grid exhibits the radial ring topology. In the case of a differentiated ring topology, the permissible loading limit should be adjusted accordingly.

If an equipment overload is identified, the flowchart checks for the extent of the equipment overloaded. In this regard, a check is done whether the equipment overload is limited to a few under-dimensioned line sections (bottleneck) or whether it is grid-wide (several feeders and/or the primary substation transformer). In the case of a bottleneck, it is recommended to apply conventional measures according to the equipment dimensions recommended in the 2nd PG and 3rd PG (sections 5.1.2 and 5.1.3) for lines and primary substation transformers, respectively.

If the overload is grid-wide and the MICT is available, LM is recommended according to the 4th PG (section 5.1.4). According to the shown analysis, a regulation of the prCPs is recommended, which corresponds to LM-V2. Moreover, the MICT rollout should be available in the downstream LV grids to ensure an economic deployment of LM. This corresponds to the LM (MV) layout, (Red. MV) layout, (B) layout, and (0) layout. Otherwise, conventional measures are recommended directly.

After resolving the equipment overloads, the flowchart moves to check the node voltages. For this, the permissible voltage range in the MV is checked according to the voltage ranges introduced in section 3.7.1. The check of the node voltage follows the line loading check as it has been stated several times that the urban MV grids are stable in terms of voltage change / voltage drop.

Generally, voltage violations are unexpected, as explained in the 6th PG (section 5.1.6). However, if a voltage violation occurs, the nominal voltage at the MV side of the primary substation transformer can be adjusted using TVR. If no voltage violations are detected, a review of the voltage range division between the LV and the MV level is recommended as explained in the 6th PG (section 5.1.6). Finally, conventional planning measures are recommended, if the voltage violation persists. It should be noted that this is a simplified flowchart that complements the existing DSO's specific planning steps and does not completely replace them.

5.3 Cross Voltage Level Planning Guidelines

With a wider view of the voltage levels, a cross voltage level analysis of the urban grid structures has determined that the grid structures of MV and LV grids strongly correlate [128]. The analysis proves that certain MV grid clusters are predominantly supplying certain downstream LV grid structures. Theoretically, this attribute can be transposed to the HV distribution grids as well. Thus, generalised cross voltage PGs can be deduced across the distribution LV and the MV levels and are valid for each of the two voltage levels separately and combined.

Beyond the aforementioned MV PGs, the three following PGs serve as an extension that spans over the two distribution voltage levels. They are deduced depending on the planning results presented in this work, as well as the planning results for the LV level published in [40], [134]. The three cross voltage PGs make use of the synergy effect between the LV and the MV levels to reduce the total grid reinforcement cross the voltage levels.

5.3.1 1st Cross Voltage Planning Guideline: Importance of cross voltage planning

> ***"Cross voltage planning of the medium and low voltage levels should be performed."***

The coupling of MV and LV levels is mostly achieved through conventional transformers with no active voltage regulation. Hence, a voltage change in one of the voltage levels crosses to either the downstream or the upper-stream voltage level. Furthermore, the 6th MV PG (section 5.1.6) proves that the originally assigned voltage range for the MV level is not exhausted and a re-investigation of the assigned voltage ranges is recommended. Hence, a cross voltage planning becomes important and needs to be performed.

Additionally, with the increased integration of new loads in the LV level, newly developed technologies such as LM operate by accessing the loads in the LV level to remedy grid violations in the MV level or even in the HV level. With a cross voltage level planning, such innovative technologies and further synergy effects can be utilised to decrease the overall grid reinforcement.

5.3.2 2nd Cross Voltage Planning Guideline: Prioritisation of equipment overloads

> ***"Contrary to the voltage limit violations, the equipment overload is the main reason for grid reinforcement measures."***

The integration of the new loads results in a significant load increase, as shown in Figure 4.22. This considerable load increase results primarily in equipment overloading, namely, transformer and line overloads. Moreover, the voltage limit violations do not occur grid-wide in all voltage levels, but rather locally in a few grid nodes – if any – and are eliminated by reinforcing the overloaded equipment.

Hence, the DSOs are recommended to increase the rating of their equipment, either by expanding the distribution grid or by renewing or reinforcing the existing equipment. In this regard, the standard equipment recommended in the 2nd and the 3rd MV PGs (section 5.1.2 and section 5.1.3, respectively) can be applied to expand or reinforce the MV grids.

5.3.3 3rd Cross Voltage Planning Guideline: Consideration of innovative technologies

"Innovative planning technologies represent an economical solution in specific grids. For the remaining grids, conventional planning measures are recommended."

The previous cross voltage PG asserts that the challenge currently faced by DSOs is a load-oriented challenge, mainly resulting in equipment overloads. These equipment overloads can only be remedied by reinforcing the grid with conventional planning measures or innovative planning technologies separately or – as in most cases – a combination of the two.

Figure 4.23 shows that LM can reduce and/or delay equipment overloads but not eliminate them and that conventional planning measures are still needed. The 4th MV PG (section 5.1.4) emphasises that–depending on the LM variant and MICT layout–the LM can be economically advantageous than performing only conventional planning measures. It also shows that the LM becomes significantly economic when the MICT infrastructure is available or the incurring costs for the MICT rollout are not considered. Hence, the innovative planning strategies can become a rather economic alternative to the conventional planning measures.

Due to the quick deployment of innovative planning technologies in comparison to the conventional planning measures, these technologies can offer a short-term solution to overcome grid violations, until conventional planning measures are deployed grid-wide. Especially in dense urban areas, implementing conventional planning measures can become challenging in terms of coordination with the different sectors (e.g., traffic) and acquiring the necessary permits. In such cases, the innovative planning technologies such as LM offer a relatively flexible solution.

By considering the aforementioned study cases of innovative planning technologies, it becomes clear that these technologies are effective both technically and economically for specific grids. So even though the innovative planning technologies represent a feasible alternative to conventional planning, a grid specific study needs to be performed to determine the most suitable PA.

With the generally valid PGs presented, it is important to analyse their dependability on several important input parameters in case they change.

5.4 Sensitivity Analysis of the Planning Guidelines

Sensitivity analysis helps to determine how much the output of a certain process or system would change, if a change occurs in one of the inputs of the system. Therefore, to ensure the general validity of the established PGs in case of a change in the input parameters, a sensitivity analysis needs to be conducted.

In the case of grid planning, the main inputs of the systems are the modelled new loads / DG along with the identified grid limits which are both explained in Chapter 3. The output of the grid planning are the PAs, which are in turn input to the primary assessment model. By analysing the results of the primary assessment model (cost of measures), the PGs are deduced.

Within this context, this section presents two sensitivity analyses that consider two important input parameters. The first analysis proposes a further parameter to the grid planning methodology by considering charging hubs as a further load type within the already considered new loads. This should validate, whether the grid planning measures would suffice in case a further load type is considered. Whereas, the second analysis proposes the consideration of the results of the alternative assessment model as the basis for deducing the PGs. This investigates whether the PGs would change, if further assessment criteria are considered and not only the costs of the measures.

5.4.1 Consideration of Charging Hubs[22]

With the increasing number of EVs, the demand for the charging hubs increases too. These consist of several CPs with high charging powers in a small space. In the context of grid planning, it is assumed that these charging hubs will initially be connected to the MV level since the expected charging power exceeds the average power of a secondary substation feeding the LV level.

Without a clear vision of the number of CPs and the charging powers that are going to be installed at the charging hubs, assumptions need to be made. [136] predicts the charging powers in the charging hubs using a statistical and machine learning approach, which focuses on forecasting the power absorbed by the EVs and the power delivered by the charging hubs. Among the investigated charging powers are the ufCPs with $150\ \text{kW} \leq P_{\text{CP}} \leq 350\ \text{kW}$ and $P_{\text{CP}} \geq 350\ \text{kW}$. An alternative approach to predicting the charging powers per charging hubs is done by [137]. In this approach, the common public data, including maps of roadways and power grids, are analysed to determine the required charging power at the charging hubs to supply the required energy to the EVs. In the performed case study, [137] concludes that charging hubs need to be equipped with the charging powers $P_{\text{CP}} = 350\ \text{kW}$ and $P_{\text{CP}} = 150\ \text{kW}$ with a higher share of $P_{\text{CP}} = 350\ \text{kW}$. Building on these conclusions, the charging power per charging hub is assumed over the investigation years.

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[22] The findings in this section have already been published in [40].

Table 5.2 lists the assumed number of CPs per charging power for the investigation years. It is assumed that a standard charging hub has two CPs with P_{CP} = 150 kW in the year 2030 and will remain until the year 2050. Starting from the year 2040, further CPs with P_{CP} = 350 kW are assumed to be added to the charging hubs, with two additional CPs per investigation year.

Table 5.2: Number of charging points per charging hub for the investigation years

Charging power	Number of charging points per charging hub		
	Year 2030	Year 2040	Year 2050
150 kW	2	2	2
350 kW	0	2	4

To achieve a uniform system for the integration of charging hubs, it is assumed that the existing conventional petrol stations will methodically be converted into charging hubs over the years or be complemented with CPs. These charging hubs are to be connected to the MV grid with appropriate DFs.

The assumed DFs and the resulting power values for the charging hubs are shown in Table 5.3. The table can be used to calculate the power values for the charging hubs and can be used for both planning perspectives. From the feeder planning perspective, when a single charging hub is connected in the feeder, the simultaneity of several charging hubs is excluded and the feeder exhibits a DF = 1 for the charging hubs. This DF decreases when more than one charging hub is connected to the feeder. Likewise, the DF from the transformer planning perspective decreases.

Table 5.3: Demand factors and power values for the charging hubs from the two planning perspectives of the medium-voltage grid planning

Planning perspective		Demand factor (DF)	Power value in [MW]		
			Year 2030	Year 2040	Year 2050
Charging hub		1.0	0.30	1.00	1.70
Feeder	(1 Charging hub in feeder)	1.0	0.30	1.00	1.70
	(>1 Charging hub in feeder)	0.8	0.80	0.80	1.36
Transformer		0.6	0.18	0.60	1.02

According to the above-given power values per charging hubs, they are then modelled in the investigated MV grids at the location of the existing petrol stations. Based on a load flow analysis, the impact of these charging hubs on the investigated MV grids is analysed in terms of line loading. Figure 5.13 (p. 116) compares the line loading in the case when the charging hubs are not connected to the grid “Without charging hub” and the case when the charging hubs are connected “With charging hubs” for the two scenarios and the HP with P_{HP} = 9 kW.

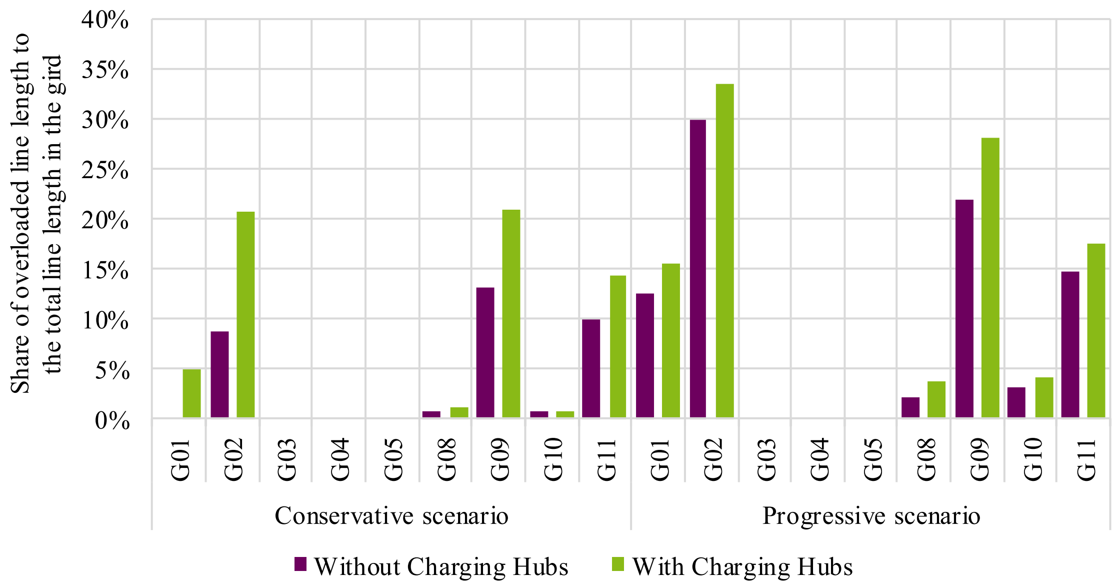

Figure 5.13: Proportion of overloaded medium-voltage line lengths in relation to the total grid line length with and without electrified filling stations for both the progressive and the conservative scenario with the heat pump of P_{HP} = 9 kW by the year 2050

It is to be noted that G06 and G07 are excluded from the analysis, as no existing petrol stations are found in the grid areas. The analysis shows that the integration of charging hubs leads to an increase in the share of the overloaded line sections by an average of 4 % of the grid line lengths. It should also be noted that the difference in overloaded line length between “without charging hubs” and “with charging hubs” is greater in the conservative scenario than in the progressive scenario. This is because the progressive scenario brings the grids to their loading limit without charging hubs, so that an increase in load due to the integration of charging hubs hardly leads to further overloading in the grid. In the case of the inner-city grids (G03 and G05) and the grid G04 with V_n = 20 kV, line overloads are unexpected, even after the integration of the charging hubs.

Apart from connecting the charging hub to the existing grid, the charging hub(s) can be connected via a dedicated feeder as a new feeder construction to supply the charging hub(s). In this case, the two grid limits, namely, the voltage range and the line overload, need to be investigated to determine the appropriate line cross-section area. This analysis is shown in Figure 5.14 (p. 117). The figure shows the maximum number of charging hubs that can be connected to a MV feeder, depending on the line cross-section area with V_n = 10 kV and its distance in km. The distance can be transformed to the voltage range grid limit, where the permissible line length is calculated according to the allowed voltage change of $\Delta V/V_n$ = -4 %. Whereas permissible line loading is considered by limiting the number of charging hubs in the line per cross-section area. The combination of these two parameters (line cross-section area and distance) gives a direct recommendation to the DSO as to which line cross-section area to be applied according to the number and the distance of the charging hubs to be connected. In comparison, the lines with V_n = 20 kV can supply double the number of the shown charging hubs, as the required feed-in current of the charging hubs decreases to half with doubling the voltage level.

The maximum possible number of charging hubs to be connected to a single dedicated feeder is five charging hubs. Due to the voltage drop over the line, the possible number of charging hubs decreases with the increasing distance between the charging hub and the primary substation.

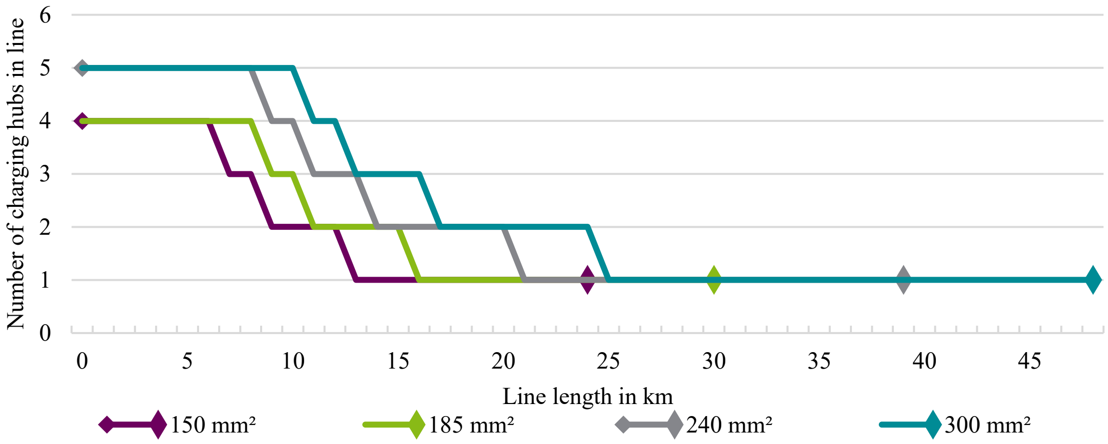

Figure 5.14: Possible number of charging hubs in a medium-voltage line per line length in km for different cross-section areas with the nominal voltage V_n = 10 kV

Referring to the impact of the charging hubs on the PGs, it can be concluded that none of the PGs is influenced by the consideration of charging hubs. Starting with the 1st PG, the determined load assumptions do not change by considering the charging hubs as they relate to the conventional, CP, and HP loads. The 2nd PG, regarding the standard line cross-section area, may, however, be influenced by the integration of charging hubs into the grid. Nevertheless, the analysis in Figure 5.13 shows that the increase in line overloads is negligible in most grids. Moreover, the 2nd PG recommends more than one standard line cross-section area that offers an extra tolerance for integrating the charging hubs into the grids. Moving on to the standard primary substation transformer capacity in the 3rd PG, in the case of connecting the charging hubs, the load development including the charging hubs load according to the load from the transformer planning perspective (given in Table 5.3) should be calculated. Consequently, the appropriate transformer capacity can be determined. Proceeding with the 4th PG regarding the usability of LM, the integration of charging hubs into the grids does not influence the analysed LM variants and layouts. As for the 5th PG, the share of overloaded lines in the different urban areas is expected to increase with the integration of charging hubs into the grids. As Figure 5.13 shows, an increase of approximately 5 % in the share of overloaded lines is expected in the progressive scenario in the year 2050. Hence, the expected share of overloaded lines recommended in the 5th PG should be adjusted accordingly. Continuing with the 6th PG, the integration of the charging hubs results in an increased voltage drop on the corresponding feeder. Hereby, the assigned voltage range division should be investigated after modelling the charging hubs in the corresponding feeder. The 7th and last PG states the robustness of MV grids with V_n = 20 kV in comparison to grids with V_n = 10 kV. This statement remains unaffected by the integration of the charging hubs.

The above-shown analysis of the charging hubs reaffirms the validity of the PGs.

5.4.2 Consideration of the Results of the Alternative Assessment Model

Besides the economic assessment of the PAs using the primary assessment model on which the MV PGs are deducted, the alternative assessment model is applied to the PAs to further compare and analyse the PAs. The following section presents the results of applying the alternative assessment model to the investigated PAs.

Figure 5.15 shows the results of the alternative assessment model for the five assessment criteria. The results are consolidated over the PAs of all the investigated MV grids for the progressive scenario in the year 2050 for the HP with $P_{HP} = 9$ kW, as it represents the maximum load development.

Referring to the scoring system in section 3.10.2, namely, equation (3.31), the top score is set $TS = 5$ representing the highest rank per assessment criterion and the lowest rank is set equal to 1. The considered LM layout is the (MV) layout as it focuses on the required MICT infrastructure at the MV level.

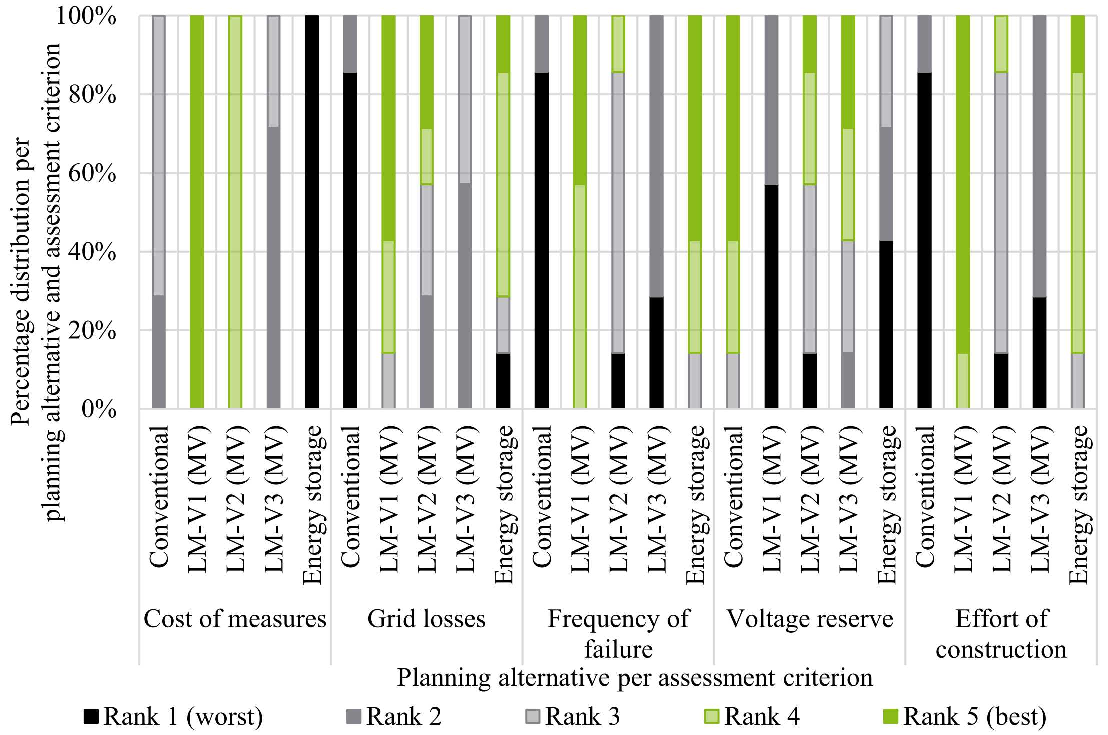

Figure 5.15: Consolidated results of the alternative assessment model for all planning alternatives over all investigated medium-voltage grids per assessment criterion for the year 2050 with the progressive scenario and the heat pump with $P_{HP} = 9$ kW based on [122] (LM = Load management, V = Variant, MV = Medium-voltage layout)

The results of the assessment criterion "Cost of measures" complies with the economical assessment already displayed in Figure 4.24 showing that the innovative technology ES is the worst in terms of costs followed by LM-V3 (MV) and then followed by the conventional planning.

This order changes from one assessment criterion to the other. For instance, the conventional planning is ranked the worst for the assessment criteria “Grid losses”, “Frequency of failure” and “Effort of construction”.

This is comprehensible since the conventional planning requires the most line measures, including parallel construction of lines, which results in frequent failures and the most effort of construction of the lines. The conventional planning is better ranked at the assessment criterion “Voltage reserve” than the innovative planning technologies, which run the grids at their limits.

Continuing with the assessment strategies summarised in Table 3.8, the following Figure 5.16 shows the results of the alternative assessment model per assessment strategy consolidated per PA over all the investigated MV grids for the progressive scenario in the year 2050 with the HP of P_{HP} = 9 kW. Similar to the previous figure, the ranking ranges from rank 1 being the worst to rank 5 being the best. The ranking shown in Figure 5.16 can easily be deduced by calculating the final score according to equation (3.32) based on the results shown in Figure 5.15 and the specific weighting values given in Table 3.8.

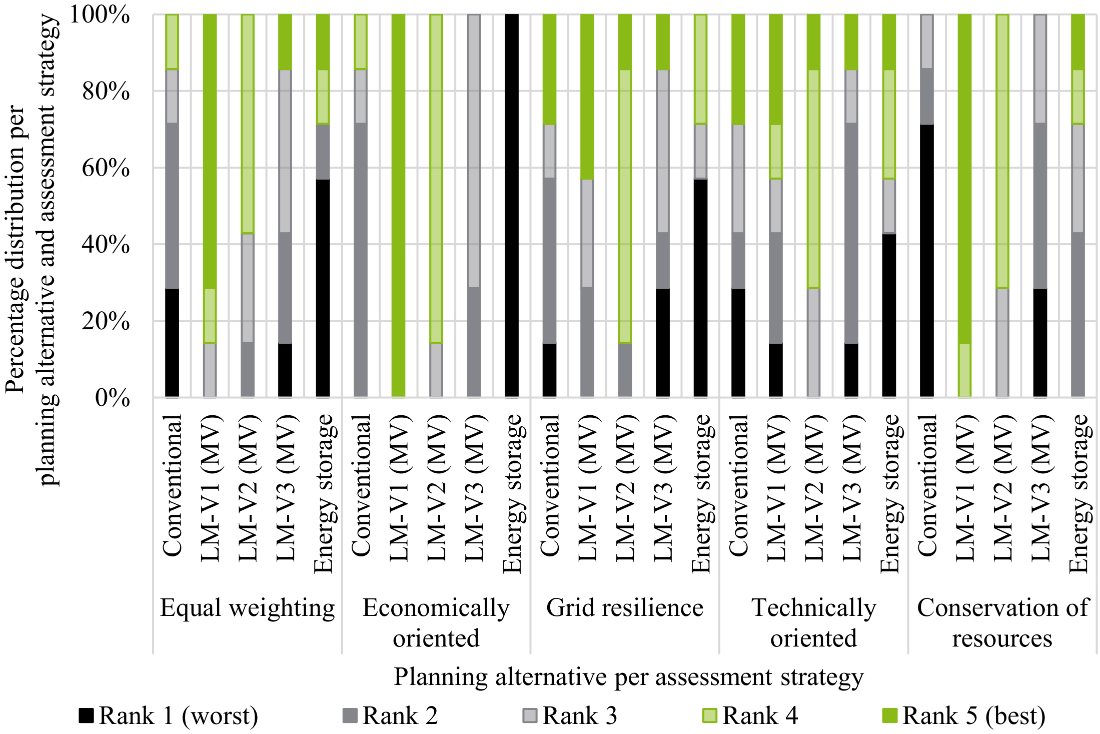

Figure 5.16: Consolidated results of the alternative assessment model for all planning alternatives over all investigated medium-voltage grids per assessment strategy for the year 2050 with the progressive scenario and the heat pump with P_{HP} = 9 kW based on [122] (LM = Load management, V = Variant, MV = Medium-voltage layout)

The “Equal weighting” assessment strategy simply combines the five assessment criteria in a single indicator. The importance of the single assessment criteria is not highlighted in this assessment strategy.

As for the assessment strategy “Economically oriented”, the ranking of the PAs in this assessment strategy coincides with the results of the assessment criterion “Cost of measures” displayed in Figure 5.15.

The following two assessment strategies “Grid resilience” and “Technically oriented” show a distribution of the rankings (4 and 5) over the PAs. The assessment strategy “Conservation of resources” favours LM-V1 (MV) and LM-V2 (MV). It is clear that by considering several assessment criteria, each of the PAs can either increase in rank or decrease. This confirms that the PAs should not only be assessed by the economical aspect but also by considering further assessment criteria. In addition, the collective consideration of the assessment criteria through several assessment strategies demonstrates the different PAs that can be adopted by DSOs according to the DSO’s specific long-term strategy. In light of this analysis, a reflection of the PGs has been done. It becomes evident that most of the PGs are not influenced by considering the results of the alternative assessment model.

Starting with the 1st PG (section 5.1.1) regarding the load assumptions, the proposed load power values are independent of the applied assessment model. Therefore, the assumed load assumptions for the new loads and the conventional loads from the feeder and the transformer planning perspectives remain unaffected by the alternative assessment model.

As for the 2nd and 3rd PG (section 5.1.2 and section 5.1.3, respectively) dealing with the standard equipment dimension, the equipment dimension is not decided based on the assessment results but rather on the required grid capacity to supply the new loads without exhibiting grid limit violations. Hence, the recommended standard line cross-section area and the standard HV/MV transformer capacity remain unchanged by the results of the alternative assessment model.

In contrast, the usability of the LM proposed in the 4th PG (section 5.1.4) correlates with the alternative assessment model, as shown in the above analysis. According to the considered assessment strategy and assessment criterion proposed by the alternative assessment model, the attractiveness of LM can significantly change.

Continuing with the 5th PG (section 5.1.5), the 6th PG (section 5.1.6), and the 7th PG (section 5.1.7), these PGs offer an overview of the impact of the new loads on the grid. Therefore, the findings presented in these three PGs are unaffected by the applied assessment model including the alternative assessment model.

5.5 Critical Discussion of the Methodology and the Results

After the PGs have been verified by the sensitivity analysis, a discussion of the applied parameters for the deduction of the PGs gives an overview of the limitations of their applicability. Therefore, this section focuses in detail on the developed methodology for the strategic grid planning presented in Chapter 3, as well as the results in terms of PAs and the deduced PGs.

5.5.1 Methodology of the Strategic Planning

The presented methodology of the strategic grid planning covers the aspects needed to ensure the readiness of the grids to incorporate the elements of the energy transition. This is guaranteed by developing a systematically consistent planning methodology that can be applied to the MV grids independent of the corresponding DSO.

First of all, the methodology starts with identifying the different grid structures of the MV grids. At this point, it is determined that this work would focus on the most common grid topology (radial ring topology). Accordingly, the permissible equipment loading is set in section 3.7.2. If the investigated MV grid has a different grid topology (e.g., meshed ring or radial), the permissible loading of the equipment has to be adjusted.

Nevertheless, the general grid planning methodology can be applied to any grid topology. The further steps in the grid planning methodology, namely, the modelling of the different load and generation types, the application of planning measures and the assessment of the PAs, are independent of the grid structure.

Secondly, the method of performing the load flow analysis is determined. Instead of performing a time-series analysis, it is decided that a load flow analysis would be performed with the differentiation of two operating points in addition to the application of DFs for loads and depreciation factors for PV from two planning perspectives. This differentiation results in four load flow situations rather than the thousands of load flow situations provided by the time-series analysis. This complicates the detection of grid limit violations and requires the utilisation of DFs.

By focusing on the application of DFs, further restrictions appear. Even though DFs are applied for each of the load types, the simultaneity between the different load types (i.e. conventional, EVs, and HPs) is not considered. Moreover, a single DF is applied for the feeder planning perspective. This case gives an exact dimension for the first line section stretching from the primary substation to the first customer or secondary substation in the ring. For the following line sections, the DFs need to be recalculated as the supplied number of loads is less than what the main feeder supplies.

Regarding the DFs for the CPs, the DFs of the "General Urban" area type are used (Figure 3.4) for the investigated MV grids. Even though the applied DFs do not consider the geographical differences between the urban area types (Metropolis, Large City and Medium-sized city), they can still provide an accurate determination of the CP load, as it overlaps the other curves.

Nonetheless, the implementation of the two operating points enables the modelling of the heterogeneous customer substation loads in a simple, accurate manner. Moreover, the adoption of the transformer and the feeder planning perspectives further enhances the accuracy of the results of the load flow analysis. Through the combined consideration of the two planning perspectives according to the corresponding DFs for a certain operating point, the future supply task of the grids can be determined accurately. Once again, this combination can generally be applied to all MV grids.

Moving on to the planning measures, the methodology of the strategic grid planning proposes a set of conventional and innovative planning measures and technologies that can be applied. Even though all available conventional and innovative planning measures and technologies are not pursued (such as direct current MV grids or single line voltage controllers), the methodology concentrates on the measures that can be widely applied to all MV grids. With a focus on the innovative planning technologies, the modelling of LM has been introduced.

Even though the presented LM considers three different load-regulating variants that regulate a specific set of load types according to the grid state, other factors should be considered for the charging power regulation. The state-of-charge of the battery and the charging time period are important aspects to be considered. The negligence of these aspects affects the end consumers directly and can lead to discomfort.

Moreover, compensation payments to the users because of the charging power regulation are not considered. Similar to the compensation payment for PV system owners in the case of a generated power regulation, it can be expected that CP owners would be granted compensation payments in the case of charging power regulation. If the compensation payments are calculated in addition to the installation and operational costs for LM, the economic attractiveness of LM can decrease in comparison to the conventional planning.

Finally, the methodology for the strategic grid planning proposes two assessment models to evaluate the various PAs of the different grids. These assessment models consider several assessment criteria that are not only relevant to the grid planning but can be calculated for any PA.

The first proposed assessment criterion is the cost of measures. Even though the cost assumptions applied in this work are specific to the investigated grids, the method can be applied to calculate the cost of measures of any PA. The further proposed assessment criteria (grid losses, frequency of failure, voltage reserve, and effort of construction) can be easily calculated using the different parameters of the final grid state.

By reviewing the individual steps proposed in the methodology of the strategic grid planning, it can be safely concluded that this methodology is comprehensible, consistent and applicable to any MV grid, although some slight improvements are possible and can be useful.

5.5.2 Application of the Planning Guidelines

Even though the methodology of the strategic grid planning is widely applicable, a few restrictions must be considered before applying the PGs.

The first input parameter to deduce the PGs is the grids themselves. Therefore, the grid parameters given in section 4.1.1 as well as in Table 8.3 (p. 155) need to be considered before applying the PGs. To put the target grid in perspective to the investigated grids, a correlation between the target grid parameters with the given grid parameters is recommended.

The 1st PG determines the future supply task of the grids in terms of load assumptions for new loads as well as for the conventional loads. It must be mentioned that these load assumptions depend on the chosen scenarios for EVs and HPs. In the case of an even more drastic penetration of EVs and HPs in the upcoming years, the load assumptions need to be adjusted accordingly. Nevertheless, the proposed load assumptions maintain their validity, in this case, as they are proposed within a range and not as a single load value.

Based on the previously chosen scenarios and the resulting future supply task, the 2nd PG recommends a standard line cross-section area for the grid with V_n = 10 kV. For the deduction of the standard line cross-section area, the cable type NA2XS2Y is used in the grid planning. In the case of a differentiated line type, the ampacity of the line may differ and, in consequence, the required line cross-section area. Furthermore, the grid topology plays an important role in the loading of the lines. If the grids are operated in a topology other than the radial ring grid topology, differentiated limits for the permissible line loading need to be identified. Moreover, in case the penetration of the new loads exceeds the foreseen penetration of the chosen scenarios, greater load development is to be expected in the grids. Nonetheless, the variety of the investigated cross-section areas from c = 150 mm^2 up to c = 300 mm^2 can suffice for different supply tasks.

The 3rd PG advises the calculation of the grid load from the perspective of the primary substation transformer to determine the appropriate transformer capacity. The calculation of the grid load depends on the load assumptions determined in the 1st PG and should be considered according to the restrictions mentioned above.

The 4th PG investigates the usability of LM in grid planning by analysing three LM variants and six LM layouts. This analysis depends on the LM modelling explained in section 3.9.2. With the technological development of LM systems, other regulation concepts can develop, such as load regulation according to energy market signals or according to a regulatory framework. In this case, the usability of LM in the grid planning may change and needs to be further investigated.

The 5th PG provides an estimation of the expected line reinforcements for different urban areas. This estimation depends not only on the urban area but also on the line loading and the existing laid line type. If the grid is already loaded to its limit or if the lines are approaching the end of their service lifetime, additional line reinforcements may become necessary.

In this case, it is advised to perform the necessary asset management measures simultaneously with the line reinforcement measures to prepare the grids for their future supply task.

The 6th PG recommends reviewing the assigned voltage range for the MV and the LV grids in the context of grid planning. This recommendation is not dependent on any further restrictions, as it is linked to the identified grid limits in the methodology of the strategic grid planning. Therefore, this PG maintains its validity independent of the individual grid characteristics.

The 7th PG analyses the grids with V_n = 20 kV compared to grids with V_n = 10 kV. This analysis provides a general insight as to what to expect in the grids of the respective voltage levels. Similar to the 6th PG, the 7th PG should be considered independent of the individual grid characteristics.

Finally, the fundamental model limitations and applied parameters are listed in the appendix (section 8.1, p. 152).

6 Conclusion and Outlook

To combat global climate change, the global energy transition accelerates the development of energy transition elements and their spread into the distribution grids. With the population being increasingly concentrated in urban centres, the emissions are reaching their highest levels in these urban centres. Hence, the electrification of high-emission sectors is desired, especially in the urban centres.

The simultaneous electrification of these sectors, namely, mobility through EVs, heating through HPs and electricity generation through PV systems, impacts all voltage levels of the distribution grid. The MV level accounts for the power supply and the voltage stability of the downstream LV grids and is the link connecting both the LV level and the HV level. Hence, this work focuses on the MV level. In this regard, the main challenge currently facing the DSOs is combating the future impact of the elements of the energy transition (i.e. EVs, HPs and PV) on the urban MV grids by performing a grid planning using technically and economically adequate planning measures. This challenge is the focus of this dissertation and has been dealt with by deducing generally valid PGs for urban MV grids.

Starting with the first unknown in this challenge, which is the impact of the elements of the energy transition, the fundamentals of these elements have been investigated. Based on this investigation, an understanding of their technical and economic framework conditions and their future development scenarios has been established. Due to the uncertainties regarding the future development of the elements of the energy transition, it is determined that the adoption of more than one development scenario is recommended to cover a range of possible development trends. Hence, a progressive and a conservative scenario are specified for each element of the energy transition.

To investigate the impact of these elements on the MV grids, a scaling down and distribution process has been developed. This process scales the countrywide scenarios down to the individual MV grids in terms of the number of units (in the case of EVs and HPs) as well as power values (in the case of PV systems). By transforming the scaled down scenarios into power values, the impact of the elements on the MV grids in terms of voltage range violation and equipment overload is determined. To further cover the uncertainties regarding the future development of the elements of the energy transition, the power assumptions for the required charging infrastructure for EVs and HPs have been diversified. As for the charging infrastructure, a differentiation between private and public CPs along with the differentiation of five different charging powers P_{CP} = 3.7 kW, P_{CP} = 11 kW, P_{CP} = 22 kW, P_{CP} = 50 kW and P_{CP} = 150 kW have been adopted. As for the HPs, three HP models with P_{HP} = 3 kW, P_{HP} = 6.5 kW and P_{HP} = 9 kW have been investigated.

By comparing the impact of the new loads (i.e. CPs and HPs) with the PV systems, it has been determined that the influence of PV systems is subsidiary to the impact of the new loads on the urban MV grids. Moreover, to further concretise the impact of CPs and HPs on the MV grids, the 1st PG (section 5.1.1) provides power value assumptions for them from the transformer and the feeder planning perspective. These power assumptions help the DSO to determine the future load power due to CPs and HPs from both planning perspectives by directly applying them to a certain MV grid.

Building on this, the second unknown in the challenge is addressed, namely, the grid planning using technically and economically adequate planning measures. In this regard, a set of conventional as well as innovative planning measures and technologies have been identified. By applying conventional planning measures to the grid planning, the 2nd PG (section 5.1.2) and the 3rd PG (section 5.1.3) could identify the standard line cross-section area and the standard primary substation transformer capacity, respectively. As for the line cross-section area, it has been recommended to maintain $c = 150\ \text{mm}^2$ (Al) or $c = 185\ \text{mm}^2$ (Al) as the current standard line cross-section area with the recommendation of an upgrade to $c = 300\ \text{mm}^2$ (Al). As for the transformer capacity, a grid-to-grid analysis of the load development has been recommended.

Moreover, three LM variants are proposed to investigate the potential of the innovative technology "Load Management". The LM variants differ in the regulated load, where LM-V1 regulates HPs and prCPs, LM-V2 regulates prCPs and LM-V3 regulates puCPs. In addition, six LM layouts with a differentiation of the MICT infrastructure rollout are proposed. The combined consideration of the three LM variants with the six layouts results in 18 possible LM variations. The technical and economic usability of these LM variations is analysed in the 4th PG (section 5.1.4). Based on the analysis, it has been determined that LM-V1 (regulating HPs and prCPs) exhibits the highest cost reduction potential, followed by LM-V2 (regulating prCPs) and finally LM-V3 (regulating puCPs). The investigation of the six LM layouts proves that the availability of the MICT infrastructure in the grids can significantly contribute to the cost reduction potential of LM in comparison to conventional planning measures. These conclusions correlate strongly with the estimated costs of the MICT infrastructure.

By addressing the unknowns of the challenge regarding the future impact of the elements of the energy transition (i.e. EVs, HPs and PV) and presenting adequate planning measures, the DSOs are left with the task of modelling and planning all their MV grids. Since this can be a resource-consuming task, approaches to simplify this task are presented.

The first approach is the selection of representative MV grids. Consequently, the planning results of these representative grids can be projected on the remaining MV grids to determine the expected load development, as well as the required planning measures. The representative MV grids can be determined according to the clustering methodology explained in section 4.1.2.

The second approach is provided in the 5th PG (section 5.1.5), the 6th PG (section 5.1.6) and the 7th PG (section 5.1.7). These three PGs offer the DSOs an overview of the required line measures according to their urban location, the expected voltage range in the grid and the robustness of their specific voltage level. These PGs give an indication to the DSO as to where to focus the reinforcement measures in the upcoming years.

Herewith, the DSO is provided with the required methodology and approaches to combat the challenge of integrating the elements of the energy transition into the urban MV grids. Generally, based on the presented detailed analysis, it can be concluded that urban MV grids are generally capable of absorbing the load development without exhibiting widely spread grid limit violations. After modelling the grids according to the future load development, it is advised to execute conventional planning measures with the recommended standard equipment in the case of a grid limit violation. These conventional planning measures can, however, be delayed or reduced by applying LM. As the cost reduction potential of LM strongly depends on the available MICT infrastructure, it is advised to analyse the MICT infrastructure before installing LM. Finally, a revision and an update of the DSO's PGs are strongly recommended.

Further research is required in several fields concerning the integration of the elements of the energy transition. Starting with the spread of these elements into the grids, the regulatory framework for the power regulation of these elements should be elaborated and established. This can provide the DSOs with a clear understanding of what to expect in their respective grid area.

As for the usage of innovative planning technologies, the modelling and application of LM need to be further analysed. Even though several LM variations are presented here, aspects such as the state-of-charge of the battery and the current energy prices can be considered for modelling the LM. The modelled regulation of CPs (either prCPs or puCPs) decreases the charging power to a minimum of $P_{\mathrm{CP}} = 3.7$ kW. Another possible regulation of the CPs is a complete turn-off of the charging power. In this case, the required line measures can be further reduced or even completely eliminated. The applicability of such a regulation mode needs further analysis, as it can enhance the economic attractiveness of LM as a viable alternative to conventional planning measures.

Regarding the grid planning, it has been manually performed in this work. Alternatively, automated grid planning can be developed with the application of an optimisation algorithm. Such an optimised automated grid planning can be significantly time-saving. Even though some advances have been reached in this field, it needs further research concerning the integration of EVs, HPs and PV as well as the application of innovative technologies as a planning measure.

7 Indices

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7.2 Abbreviations

Abbreviation	**Extended term**
Al	Aluminium
BDI	“Bundesverband der Deutschen Industrie” translated to Federation of German Industries
BWP	“Bundesverband Wärmepumpe” translated to “Federal Heat Pump Association”
CapEx	Capital Expenditure
cons.	Conservative scenario
CP	Charging point
CS	Customer substation
dena	“Deutsche Energie Agentur” translated to German Energy Agency
DF	Demand factor
DG	Decentralised generation
DGA	Decentralised grid automation
DSO	Distribution system operator
ES	Energy storage
EV	Electric vehicle
HP	Heat pump (electric)
HV	High-voltage
LM	Load Management
LTE	Long-Term Evolution
LV	Low-voltage
MICT	Measurement, information and communication technology
MV	Medium-voltage

NA2XS2Y	N: According to the VDE standard, A: Aluminium conductor, 2X: Cross-linked polyethylene insulation, S: Silk whipping, 2Y: Polyethylene
NAKBA	N: According to the VDE standard, A: Aluminium conductor, K: Copper-tape, BA: Aluminium armouring
NEP	"Netzentwicklungsplan" translated to "Grid development plan"
OpEx	Operational Expenditure
p.	Page
PA	Planning alternative
PG	Planning guideline
prCP	Private charging point
prog.	Progressive scenario
puCP	Public charging point
PV	Photovoltaic
RTU	Remote terminal unit
SIM	Subscriber Identity Module
SS	Secondary substation
TVR	Transformer voltage regulation
ufCP	Ultrafast charging point
V	Load management variant

7.3 Notations

Symbol	**Physical meaning**
AC_a	The physical value of a certain assessment criterion a
c	The line cross-section area
$\cos(\varphi)$	The power factor
$DF_{P_N,n}$	The demand factor of the nominal load power P_N for the specific number of loads n
$DF_{P_{CPi},n_{CPi}}$	The demand factor for the charging power P_{CPi} for the individual number of charging points n_{CPi}
$DF_{P_{CPi},\Sigma n_{CP}}$	The demand factor for the charging power P_{CPi} for the total number of charging points in the grid Σn_{CP}
$DF_{P_{eff},n_{CPi}}$	The demand factor for the charging power P_{eff} for the individual number of charging points n_{CPi}
$DF_{P_{eff},\Sigma n_{CP}}$	The demand factor for the charging power P_{eff} for the total number of charging points in the grid Σn_{CP}
$DF_{P_{eff,F},n_{CP,F}}$	The demand factor for the effective charging power $P_{eff,F}$ from the feeder planning perspective with the number of charging points in a feeder $n_{CP,F}$
$EV_{city,y}$	The number of electric vehicles on the city level at the year y
$EV_{country,y}$	The number of electric vehicles on the country level at the year y
$EV_{state,y}$	The number of electric vehicles on the state level at the year y
F	The frequency of failure
$F_{FP,state}$	The distribution factor for the parameter “funding projects for electromobility” on the state level
$F_{NoB,state}$	The distribution factor of the parameter “Number of buildings” on the state level
$F_{NoCO,state}$	The distribution factor of the parameter “Number of car owners” on the state level
$F_{NoEV,state}$	The distribution factor of the parameter “Number of electric vehicles” on the state level
$F_{NoV,city}$	The distribution factor of the parameter “Number of registered vehicles” on the city level
$F_{NoV,state}$	The distribution factor of the parameter “Number of registered vehicles” on the state level
$F_{Pa,city}$	Distribution factor for a scaling down parameter on the city level

$F_{\mathrm{Pa,state}}$	Distribution factor for a scaling down parameter on the state level
$F_{\mathrm{Pop,city}}$	The distribution factor of the parameter “Population” on the city level
$F_{\mathrm{Pop,state}}$	The distribution factor of the parameter “Population” on the state level
$F_{\mathrm{PopD,city}}$	The distribution factor of the parameter “Population density” on the city level
f_{N}	The nominal frequency
I	The flowing current
I_{F}	The current measurement of a medium-voltage feeder
I_{max}	The maximum permissible current
I/I_{th}	The line loading
I_{th}	The rated thermal equipment current
$I_{\mathrm{secondary}}$	The current stay-set pointer value at the secondary substation medium-voltage/low-voltage transformer
k	A certain equipment type in the grid
k_{city}	The number of detached houses on the city level
k_{state}	The number of detached houses on the state level
k_{street}	The number of detached houses on the street level
l	The line length
λ_{k}	The failure rate of the equipment type k in a year
n	The number of units for the specific load type
$n_{\mathrm{commercialEV,grid}}$	The number of commercial electric vehicles in a medium-voltage grid
$n_{\mathrm{commuterEV,grid}}$	The number of commuter electric vehicles in a medium-voltage grid
n_{CP}	The number of charging points
Σn_{CP}	The total number of charging points in a grid
$n_{\mathrm{CP,F}}$	The number of charging points in a feeder
n_{k}	The total quantity in meters or the number of units of a certain equipment type k

$n_{\mathrm{privateEV,grid}}$	The number of private electric vehicles in a medium-voltage grid
$n_{\mathrm{puCP,grid}}$	The number of public charging points in a medium-voltage grid
PA_{b}	Represents a certain planning alternative *b*
$P_{\mathrm{conv,F}}$	The household loads per building connection for the load calculation per secondary substation for dimensioning the feeders
$P_{\mathrm{conv,T}}$	The household loads per building connection for the load calculation per secondary substation for dimensioning the primary substation transformer
P_{CP}	The nominal active charging power for a charging point
P_{CPi}	The nominal active charging power for a charging point type *i*
$P_{\mathrm{CP,F}}$	The nominal active power for a charging point from the feeder planning perspective
$P_{\mathrm{CP,T}}$	The nominal active power for a charging point from the transformer planning perspective
P_{DG}	The distributed generation power
P'_{DG}	The modelled distributed generation power
$P_{\mathrm{eff,F}}$	The effective average charging power from the feeder planning perspective
$P_{\mathrm{eff,T}}$	The effective average charging power from the transformer planning perspective
P_{HP}	The nominal active power for a heat pump
$P_{\mathrm{HP,T,F}}$	The active power for heat pumps per building connection for dimensioning the primary substation transformer and the feeders
$P_{\mathrm{inst.}}$	The installed electric power of a photovoltaic system
P_{load}	The active load power
P'_{load}	The modelled load power
$P_{\mathrm{load,CP}}$	The load power for a charging point from the transformer planning perspective
$P_{\mathrm{load,CP,F}}$	The load power for a charging point from the feeder planning perspective
P_{customer}	The active load power at a customer substation
$P_{\mathrm{load,F}}$	The active load power for a certain load from the feeder planning perspective

$P_{\mathrm{load,T}}$	The active load power for a certain load from the transformer planning perspective
P_{N}	The nominal active power
P_{peak}	The peak load power
$P_{\mathrm{prCP,F}}$	The mean effective charging power for private charging points per building connection for dimensioning the feeder
$P_{\mathrm{prCP,T}}$	The mean effective charging power for private charging points per building connection for dimensioning the primary substation transformer
$P_{\mathrm{puCP,F}}$	The mean effective charging power for public charging points per building connection for dimensioning the feeders
$P_{\mathrm{puCP,T}}$	The mean effective charging power for public charging points per building connection for dimensioning the primary substation transformer
P_{PV}	The photovoltaic power
$P_{\mathrm{PV,country}}$	The total installed photovoltaic power on the country level
$P_{\mathrm{PV,LV,y}}$	The photovoltaic power on the low-voltage level at the investigation year y
$P_{\mathrm{PV,LV,city,y}}$	The photovoltaic power in the low voltage on the city level at the investigation year y
$P_{\mathrm{PV,LV,district,y}}$	The photovoltaic power in the low voltage on the district level at the investigation year y
$P_{\mathrm{PV,LV,state,y}}$	The photovoltaic power in the low voltage on the state level at the investigation year y
$P_{\mathrm{PV,LV,street,y}}$	The photovoltaic power in the low voltage on the street level at the investigation year y
r	The interest rate
S	The flowing apparent power
$S_{\mathrm{max}}/S_{\mathrm{r}}$	The transformer loading
S_{r}	The rated apparent power
SF_{F}	The scaling factor for a medium-voltage feeder
T	The temperature
TS	The top score of a certain assessment criterion over all investigated planning alternatives
V	Voltage
V_{max}	The maximum permissible voltage

V_{min}	The minimum permissible voltage
V_n	The nominal voltage
V_{N}	The voltage at a given node in the grid
$V_{\mathrm{N,min}}$	The minimum node voltage level in the grid
$V_{\mathrm{Pa,city}}$	Absolute value of a scaling down parameter on the city level
$V_{\mathrm{Pa,country}}$	Absolute value of a scaling down parameter on the country level
$V_{\mathrm{Pa,state}}$	Absolute value of a scaling down parameter on the state level
$v_{\mathrm{PV,LV}}$	The ratio of the installed photovoltaic power in the low-voltage level to the total installed photovoltaic power in the country
V_{R}	The voltage range
V_{res}	The voltage reserve
V_{set}	The set point voltage
ΔV	Slow voltage change
$W_{\mathrm{AC_a}}$	The weighting value of an assessment criterion a
$w_{\mathrm{i,y}}$	A specific weighting term for scaling down the number of electric vehicles on the state level for the year *y*
$w'_{\mathrm{i,y}}$	A specific weighting term for scaling down the number of electric vehicles on the city level for the year *y*
x_{DF}	A demand factor constant dependent on the load type
y	An investigation year (*y*=2030, 2040 or 2050)

7.4 Definitions

Term	Definition
Charging point	A power outlet at which only one electric vehicle can be charged.
Conventional load	Household, commercial and industrial loads
Customer substation	A substation supplying a single consumer on the MV level
Demand factor	"The ratio, expressed as a numerical value or as a percentage, of the maximum demand of an installation or a group of installations within a specified period, to the corresponding total installed load of the installation(s)" [138]
Demand side management	"Process that is intended to influence the quantity or patterns of use of electric energy consumed by end-use customers" [118]
Feeder	"An electric line originating at a main substation and supplying one or more secondary substations" [73]
Inner-city	Areas with large building sizes, very densely built-up area density, compact building shape and not squared buildings without a particular orientation. [135]
Load	"Device intended to absorb power supplied by another device or an electric power system" [139]
New load	A charging point or heat pump load
Operating point	"Point on a characteristic curve representing the values of variable quantities at which a system is operating" [78]
Privately accessible charging point (Private charging point)	"When the access to a charging point is granted only to a group of people that are already or can be determined, it is not identified as a publicly accessible charging point within the context of this regulation." [43]
Planning alternative	A final grid model in the year 2050 for a specific scenario and heat pump model where the expected grid violations are resolved either by solely conventional planning measures or with one of the innovative planning technologies in combination with conventional planning measures.
Primary substation	A substation with one or more transformers converting from the HV level to the MV level

Publicly accessible charging point (Public charging point)	“In the context of this regulation, a charging point is publicly accessible if it is located either on a public road space or on a private land, provided that the parking space of the charging point is accessible from an undefined group of people or by a group of people that can be identified according to general characteristics.” [42]
Secondary substation	A substation with one or more transformers converting from the MV level to the LV level
Single-outage occurrence or a single contingency	“Outage occurrence caused by only one system component” [107]
Suburban area	Areas with medium and small building size, low built-up area density, compact building shape and squared buildings without a particular orientation. [135]
Switching station	A MV substation without voltage conversion transformers
Urban area	Areas with large and medium building size, dense built-up area density, complex and compact building shape and squared buildings without a particular orientation. [135]

8 Appendix

8.1 Model Limitations

The results presented in this dissertation are achieved from the strategic grid planning for the selected MV grids. The grid structure parameters for the investigated grids described in section 8.3 (p. 154) are coordinated in consultation with the respective DSO. Accordingly, the grids are modelled as close to reality as possible, but in a systematically standardised way over all DSOs. Based on an assessment of the different PAs resulting from the grid planning, the PGs are deduced as described in section 5.1.

Input parameters:

- The year 2021 represents the base year for the grid parameters (e.g., load, etc.).
- The grids are designed for the load task of the two selected scenarios (conservative / progressive) for EVs, HPs and PV systems.
- Grid planning for the years 2030, 2040 and 2050 is performed across the investigation years.
- Changing charging power distributions are assumed over the investigation years.
- For prCPs, P_{CP} = 3.7 kW, P_{CP} = 11 kW and P_{CP} = 22 kW are assumed.
- For puCPs, P_{CP} = 11 kW, P_{CP} = 22 kW, P_{CP} = 50 kW and P_{CP} = 150 kW are assumed.
- The assumed distribution of each of the charging powers is given in Table 3.1.
- For HPs, P_{HP} = 3 kW, P_{HP} = 6.5 kW and P_{HP} = 9 kW are assumed.

Modelling/calculation:

- Power flow calculations are carried out in PSS®SINCAL.
- The assumed voltage range for the grid planning is applied according to Figure 3.6.
- The DFs for CPs are applied according to Figure 3.4.
- The DFs for HPs are applied according to Figure 3.5.
- The depreciation factors for PV systems are applied according to Table 3.4.
- CPs, HPs, and PV systems are assumed with a power factor of $cos(\varphi)$ = 1.
- LM is modelled according to section 3.9.2.
- ES is modelled according to section 3.9.3.
- Static grid planning is carried out across all investigation years.

Technical-economic evaluation:

- Working capital costs are considered for the cost calculation according to section 8.2.
- The cost calculation method explained in section 3.10.1 serves as the basis for the cost calculation.

- The base year is 2021.
- The years 2025, 2035 and 2045 are considered to be the investment years.

8.2 Cost Assumptions

Table 8.1: Assumed costs for the applied medium voltage equipment

Equipment	Parameter	Value	Unit
3-phase NA2XS2Y Cable 10/20 kV	Service life (calculated)	45	[a]
	Operational costs	2.5	[% CapEx/a]
	Price increase	0.5	[%/a]
c = 150 mm² single	Cable cost + installation	225,000	[Euro/km]
c = 150 mm² parallel	Cable cost + installation	+ 50,000	[Euro/km]
c = 185 mm² single	Cable cost + installation	237,500	[Euro/km]
c = 185 mm² parallel	Cable cost + installation	+ 65,000	[Euro/km]
c = 240 mm² single	Cable cost + installation	250,000	[Euro/km]
c = 240 mm² parallel	Cable cost + installation	+ 80,000	[Euro/km]
c = 300 mm² single	Cable cost + installation	275,000	[Euro/km]
c = 300 mm² parallel	Cable cost + installation	+ 95,000	[Euro/km]
Energy storage	Service life (calculated)	16	[a]
	Operational costs	2.5	[% CapEx/a]
	Basic cost	46,000	[Euro/unit]
	Power cost for 2h capacity	550	[Euro/kW]
Decentralised automation	Service life (calculated)	15	[a]
	Operational costs	2.5	[% CapEx/a]
	Basic cost	15,000	[Euro/unit]
	MV-sensor	8,000	[Euro/unit]
	LV-sensor	3,500	[Euro/unit]

HV/MV substation components	Service life (calculated)	40	[a]
	Operational costs	2.5	[% CapEx/a]
	New construction	1,500,000	[Euro/unit]
	GIS switchgear	70,000	[Euro/unit]
	AIS switchgear	60,000	[Euro/unit]
	Disconnector	4,500	[Euro/unit]
Transformer	Service life (calculated)	40	[a]
	Operational costs	2.5	[% CapEx/a]
S_r = 31.5 MVA	Transformer cost + installation	450,000	[Euro/unit]
S_r = 40.0 MVA	Transformer cost + installation	500,000	[Euro/unit]
S_r = 63.5 MVA	Transformer cost + installation	650,000	[Euro/unit]

8.3 Grid Parameters

Table 8.2: Classification of the investigated medium-voltage grids in terms of the building and urban structure (X = high share, O = low share, - = negligible or not present)

Structure	G01	G02	G03	G04	G05	G06	G07	G08	G09	G10	G11
One/Two family houses	X	X	-	X	-	-	X	-	-	-	-
Multi-family houses	O	X	X	O	X	X	-	X	X	X	X
Industrial	-	O	O	X	O	-	-	X	O	O	O
Suburban	X	X		X			X				
City								X	X	X	X
Inner-city			X		X	X					

Table 8.3: Grid structure parameters including the values for the new load development scenario (values of the charging points and heat pumps for each grid: the first row is the conservative scenario, the second row is the progressive scenario, where the first column is the year 2030, the second column is the year 2040 and the third column is the year 2050)

Grid/ Voltage Level	Installed Transformer Power (MVA)	Total line length (km)	No. of secondary/ Customer stations	No. of Building Connections	No. of Metering Points	No. of Feeders	No. of Charging Points			No. of Heat Pumps		
G01/ 10 kV	2 x 12.5	40.9	44 / 11	3,095	8,797	6	1,194	2,175	3,834	144	178	253
							1,913	4,072	8,433	182	344	544
G02/ 10 kV	2 x 40	40.0	37 / 18	4,041	15,982	14	1,637	3,343	6,028	186	229	323
							2,726	6,319	12,014	235	444	708
G03/ 10 kV	1 x 31.5	16.6	41 / 3	484	4,139	13	195	399	773	20	24	40
							324	758	1,673	25	54	83
G04/ 20 kV	3 x 40	70.9	39 / 24	1,815	6,728	9	737	1,512	2,905	84	103	147
							1,226	2,849	6,280	107	201	320
G05/ 10 kV	1 x 40	16.9	22 / 16	504	4,221	16	203	420	803	24	29	41
							340	791	1,745	29	55	87
G06/ 10 kV	-	4.6	7 / -	182	2,142	2	63	119	210	7	8	14
							98	231	483	14	21	35
G07/ 10 kV	-	17.0	9 / -	2,034	2,601	2	657	1,287	2,385	90	117	162
							1,125	2,529	5,409	117	225	360
G08/ 10/20 kV	2 x 63	183.4	170 / 62	5,312	37,802	32	2,156	4,415	8,517	240	298	425
							3,623	8,341	17,557	305	588	935
G09/ 10 kV	1 x 40	44.9	59 / 3	2,663	14,400	15	1,076	2,070	3,500	122	147	212
							1,804	3,707	7,461	154	295	471
G10/ 10/20 kV	2 x 63	134.8	131 / 46	4,619	48,424	26	1,869	3,854	7,398	213	265	374
							3,135	7,229	15,961	275	517	816
G11/ 10/20 kV	2 x 63	174.9	171 / 66	6,546	54,478	23	2,686	5,522	10,646	297	368	526
							4,482	10,396	20,804	375	721	1,151

8.4 Assumptions of the Scaling Down Process

Table 8.4: Assumed values of the weighting terms for the scaling down of electric vehicles from the country level to the state level over the investigation years [140]

Weighting terms	Year 2030	Year 2040	Year 2050
w_{Pop}	0.100	0.150	0.210
W_{NoEV}	0.600	0.400	0.010
W_{NoCO}	0.100	0.100	0.060
W_{RB}	0.100	0.075	0.010
W_{NoB}	0.100	0.075	0.010
W_{NoV}	0.000	0.200	0.700

Table 8.5: Assumed values of the weighting terms for the scaling down of electric vehicles from the state level to the city level over the investigation years [140]

Weighting terms	Year 2030	Year 2040	Year 2050
w'_{Pop}	0.55	0.55	0.55
w'_{PopD}	0.05	0.05	0.05
w'_{NoV}	0.40	0.40	0.40

8.5 Applied Rate of Failure of Equipment

Table 8.6: Rate of failure of equipment in compensated medium-voltage grids

Equipment type		Voltage level	Rate of failure [1/a]
Cable	Paper isolated	10 kV	0.01519
	Cross linked polyethylene	10 kV	0.00201
	Paper isolated	20 kV	0.00828
	Cross linked polyethylene	20 kV	0.00201
Primary substation	HV/MV transformer	110 kV/10 kV or 110 kV/20 kV	0.006285

Publications

Within the scope of my work at the Chair for Power Systems Engineering at the University of Wuppertal, the following publications have been produced:

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