

# Comparison of Simplified and Detailed Calculation Methods for Forecasting Load Development in Low-Voltage Grid Areas

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**Abstract:** The electrification of the transport and heat sectors will significantly increase and reshape demands in urban distribution grids. To support distribution system operators in large-scale planning studies, this work compares simplified and detailed probabilistic methods to forecast future low-voltage load developments and to assess resulting grid impacts. Three representative urban grids are analysed for a future scenario with high shares of heat pumps and electric vehicles. The study evaluates modelling accuracy with respect to transformer loading, line loading and node voltages, as well as the associated computational effort. Results show that a 10-minute time resolution provides a robust and practice-oriented compromise between accuracy and runtime. Increasing the number of probabilistic calculation iterations generally improves the capture of rare critical grid states, but benefits saturate at higher iteration numbers. Simplifying heat pump modelling via a model based on the average system efficiency of the heating system can substantially reduce computation time while maintaining comparable peak loading results. Load-profile pooling approaches reproduce classic Monte Carlo results at significantly lower computational cost and are - due to their required initial invest for creating the load profile pools - particularly suited for large-scale studies. Finally, an approach based on simultaneity factors offers a conservative, fast evaluation and can be applied in cases where calculation time is crucial or static, worst-case load estimates are sufficient.

**Keywords:** Load Modelling, Grid Planning, Monte Carlo Simulation, Simultaneity Factors, Electric Vehicles, Heat Pumps, Distribution System Operator

## 1 Motivation and Objectives

Due to advancing sector coupling, distribution grids – especially in urban areas – are facing structural changes. Significant increases in load are to be expected, in particular due to the transition of the transport and heating sector and the corresponding increase in electric vehicles and heat pump-based heating systems. In order to ensure a future-oriented and dependable energy supply, grid expansion measures are unavoidable in many cases. In this context,

reliable load forecasts are essential for the correct dimensioning of the operating equipment such as transformers and cables.

At higher voltage levels load forecasting is comparatively simple, since it is possible to utilize standard load profiles due to the high number of respective consumers (increasing accuracy with increasing aggregation, see also law of large numbers). In low-voltage grids this is much more complex due to the smaller underlying consumer base and the resulting higher probability of overlapping extreme cases. In order to achieve a reliable forecast for a high number of grids in different scenarios, a fundamental conflict of interest exists between result precision and computational intensity. Therefore, this work compares different approaches developed for load forecasting at the low-voltage level in terms of their accuracy and computational complexity using typical, representative urban grid areas (see also section 4) as examples and provides application recommendations for grid operators.

A more detailed description of the different calculation variants to be compared is provided in section 3. The general methodology and approach of this study are explained in the following section.

## 2 Methodology

To evaluate the different calculation methods, typical representative network areas are defined as example areas for the analysis in a first step. Based on [1], three typical grids representative for urban areas are utilized here: An area with dense building structure (primarily residential use), an area with loose building structure (primarily residential use), and an area primarily used for commercial and retail purposes. These networks are based on existing grid areas and are further used to compare the different modelling approaches. More detailed descriptions of the three network areas are provided in section 4.

In order to determine the resulting load flows in the respective networks, both, a simultaneity-based approach – which is comparably simple and computationally less intensive – and

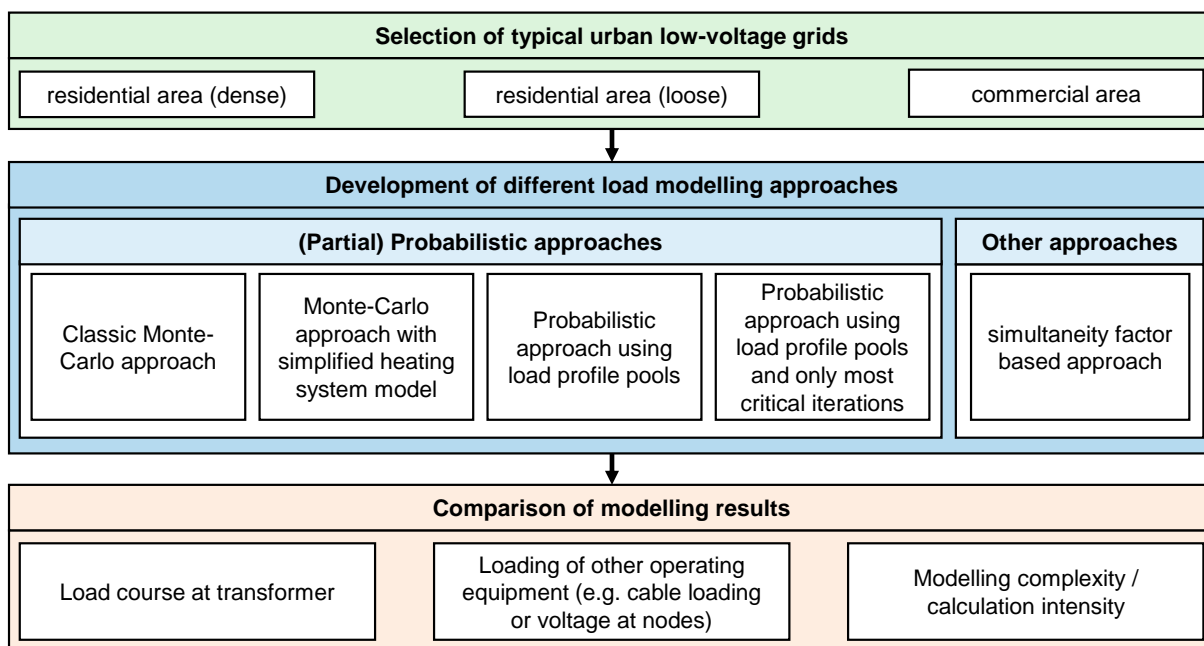


Figure 1: Overview of the chosen methodology

several more complex probabilistic approaches are applied. Probabilistic analyses involve classic Monte Carlo simulations (MC) as well as Monte Carlo simulations with simplified heating system modelling (MC + SHSAP). In addition to this, pooling approaches are developed, in which load profiles of a certain load type (e.g., home charging point for electric vehicles) are pre-produced once using a Monte Carlo simulation and stored in a database, from which they can later be retrieved as needed without having to regenerate the individual profiles each time. A more detailed description of the modelling variants is provided in section 3. The resulting load profiles and simultaneity curves are modelled in a Python environment, while the load flow calculation is carried out in DlgSILENT PowerFactory. For the (partially) probabilistic approaches, a quasi-dynamic simulation is done in PowerFactory, while for the simultaneity factor-based approach, the low voltage load flow analysis method is utilized (for an explanation of the different PowerFactory methods, see [2]).

The significance of the time resolution of the quasi-dynamic simulation, varying iteration numbers, and practical strategies in order to reduce the number of iterations are also assessed here. Finally, the results are compared in terms of modelling complexity and resulting loading of the operating equipment. Recommendations for application by distribution system operators are derived. The approach is summarized in Figure 1.

### 3 Description of the Different Calculation Methods

This section presents all different calculation variants to be compared, which range from purely probabilistic approaches to probabilistic pooling approaches to simultaneity-based approaches. Section 3.1 first explains the Monte Carlo approach and associated sub-variants.

#### 3.1 Monte Carlo Simulation

In the Monte Carlo simulation, the load profiles of the respective consumer types are modelled based on various influencing factors and their respectively defined probability distributions. Depending on the type of load, different influencing factors must be taken into account. Factors

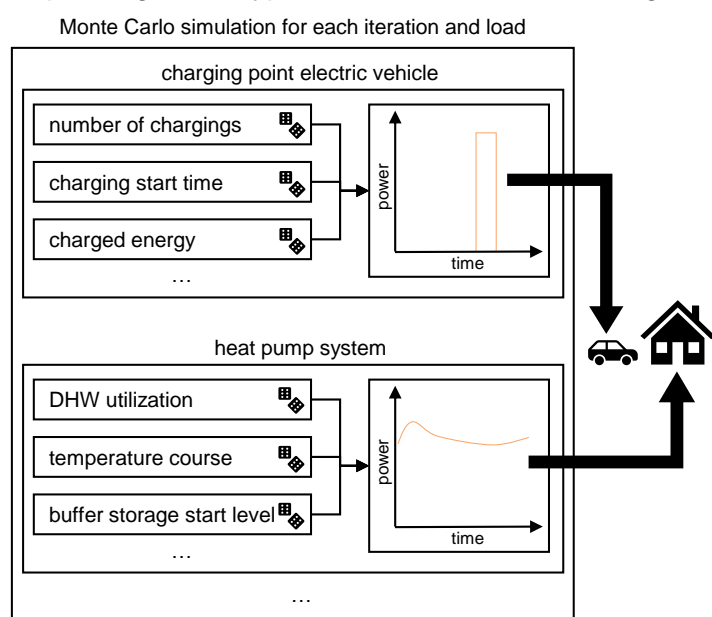


Figure 2: Illustration of Monte Carlo simulation using the example of a charging point and a heat pump system

such as the start time of the charging process, the amount of energy charged, and the relevant charging power play an important role at the modelling of an electric vehicle charging point. In a heat pump system (HP), on the other hand, aspects such as the domestic hot water (DHW) withdrawal, the profile of the ambient temperature, and the level of the buffer tank at the start of the simulation are relevant. Figure 2 provides an example illustration thereof. Individual load curves are determined here for each load and analysis iteration. The load time series is generally modelled in

a one-minute resolution. The modelling of the heat pump systems is based on the heating system models developed in [3] and [4]. The “High-resolution Heating System Model” in combination with the base scenario defined there is utilized, whereby a heating curve of A-10/W51 is assumed for all buildings. The heating demand is considered every minute individually for each building based on an existing building data base [5] for the respective buildings. The analyses are carried out during the period of standard outdoor temperature, as this is when the highest power consumption has to be expected.

The models published in [6] are used to determine the power consumption of charging points for electric vehicles (EVs), with the load profile also being simulated on a winter working day. The following assumptions do generally apply:

- Charging powers of EV: 11 kW AC and 160 kW DC
- Charging power of private home charging point: 11 kW AC
- Charging power of private work charging point: 11 kW AC
- Charging power of public AC charging station: 2 x 22 kW AC
- Charging power of public DC charging station: 53 kW

In the case of DC charging points, rectifier losses are already taken into account by additional power consumption of the charging stations (see also [6]). In order to model the household loads the load profile generator from [7] is utilized to reproduce load profiles and herewith simulate the respective household loads. The profiles are calibrated according to the methodology described in [6]. Households are always assumed to be two-person households, since this corresponds to the typical household size in Germany [8]. A working day in winter is modelled, whereby the annual energy consumption is set to 2,900 kWh per household, which is an average value for a two-person household in Germany [9].

In the absence of reliable information on individual commercial buildings and the underlying commercial utilization type, the standard load profile for commercial use (profile G25 for a working day in January, see also [10]) is utilized to estimate the commercial power consumption. This enables the active power demand of each building to be determined individually for all different load types. In order to consider the reactive power demands, the following power factors are assumed for purposes of simplification:

- Heat pump systems (modulating): 0.95 overexcited ([11] shows that the power factor of heat pumps can vary significantly depending on the model and operating point. Since this paper assumes modulating heat pumps with frequency converters (and not fixed-speed heat pumps), a power factor of 0.95 overexcited is assumed.)
- Charging infrastructure for EVs: 1.0 (see [6])
- Household loads: 1.0 (simplification based on [12] and [13]: reactive power consumption by households is typically quite low. The analysis conducted during the development of the load profile generator utilized in this work also implies that the power factor of households averages around one [7])
- Commercial loads: 0.98 underexcited (cf. [6])

The load profiles are generated entirely in a Python environment. From there, the profiles are automatically imported into PowerFactory, where they are assigned to their building specific grid connection points (GCPs) and are utilized for a quasi-dynamic simulation. The results of this simulation do then provide relevant insights into the resulting equipment loadings and possibly occurring limit violations.

### 3.1.1 Monte Carlo Simulation with Simplified Heating System Modelling

In the calculation variant Monte Carlo Simulation with Simplified Heating System Modelling, everything is identical to the Monte Carlo simulation explained above, with the exception of the heating system modelling. In order to model the active power demand of the heating system the “Simplified Heating System Average Performance Model” developed in [3] is utilized here instead of the “High-resolution Heating System Model”. Instead of using a detailed thermal building model, a constant electrical power consumption of the heating system is now approximated and used based on the overall efficiency of the heating system. Although this reduces the accuracy of the resulting load profile, it eliminates the need for the computationally intensive, high-resolution heating system modelling. All other calculation steps remain the same as in the previous section.

### 3.2 Probabilistic Approach with Load Profile Pools

In contrast to the previous Monte Carlo Simulation, the Probabilistic Approach with Load Profile Pools does not generate new load profiles for each iteration and consumer. Instead, a large number of load profiles are created in advance for each consumer type and then stored in a database (“load profile pool”). The Monte Carlo simulation presented in section 3.1 is utilized to generate the individual profiles of the pool. Subsequently, for each iteration a corresponding load profile is randomly selected from the pool and utilized. Figure 3 illustrates the procedure with an example.

Since commercial loads are represented by the standard load profile in the model, load profile pools are only created for charging points, heat pump systems, and households. As already

Pre-generated load profile pools

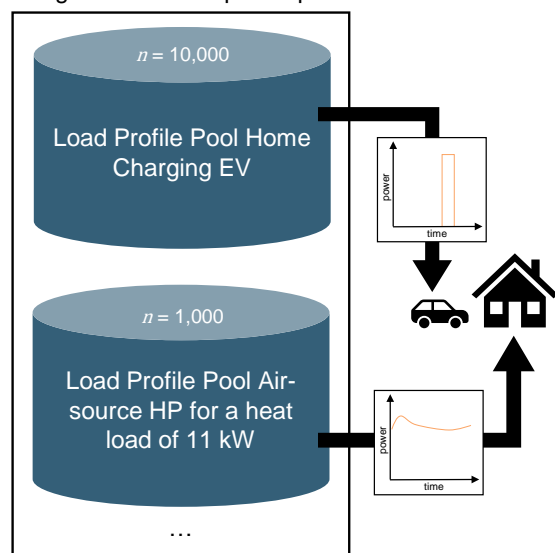


Figure 3: Illustration of the pooling approach using the example of a charging point and a heat pump

explained in section 3.1, households are always modelled as two-person households, which is why one load profile pool is sufficient here. For EV-related loads, separate load profile pools must be created for all relevant charging point types (e.g., private home charging, private charging at work, public AC charging, public DC charging, etc.), as these can vary greatly in terms of power demand and time course. The procedure is more complex in the case of heat pump systems. In addition to the different types of heat pumps (air-, ground-, and water-source), the heat load of the building and the number of residents – which influences DHW consumption – also play an essential role, as the dimensioning of the HP system depends on these factors. The HP profile pools are therefore grouped according to HP

technology, heating load of the building, and number of supplied households. An adaptive group width is applied here in case of the heat load in order to limit the number of different load profile pools required. The adaptive heat load group width is used to ensure both fine resolution in the range of lower heat loads and appropriate aggregation in ranges of higher heat loads,

without having too many profile groups. The heat load  $\dot{Q}_{\text{SHL}}$  is divided into consecutive intervals, each of which is assigned a specific group width  $w(\dot{Q}_{\text{SHL}})$ . For building heat loads in the range of  $0 \text{ kW}_{\text{therm}} \leq \dot{Q}_{\text{SHL}} < 10 \text{ kW}_{\text{therm}}$  the class width is  $1 \text{ kW}_{\text{therm}}$ , in the range of  $10 \text{ kW}_{\text{therm}} \leq \dot{Q}_{\text{SHL}} < 20 \text{ kW}_{\text{therm}}$  the class width is  $2 \text{ kW}_{\text{therm}}$  and so on. The adaptive class width can therefore be described by function (1).

$$w(\dot{Q}_{\text{SHL}}) \begin{cases} 1, & 0 \leq \dot{Q}_{\text{SHL}} < 10 \\ 2, & 10 \leq \dot{Q}_{\text{SHL}} < 20 \\ 3, & 20 \leq \dot{Q}_{\text{SHL}} < 30 \\ \dots & \dots \end{cases} \quad (1)$$

$\dot{Q}_{\text{SHL}}$  Standard heat load of building in  $\text{kW}_{\text{therm}}$

$w(\dot{Q}_{\text{SHL}})$  Group width of load profile pool in  $\text{kW}_{\text{therm}}$

Each building is then assigned to a group whose boundaries are determined by the corresponding class width. This approach takes the variability of the heat load distribution into account and ensures an appropriate grouping that guarantees both result accuracy and a limited amount of different load profile pools.

The number of profiles contained in the pools ranges between 1,000 and 10,000 depending on the consumer type. For consumers such as HPs, only 1,000 profiles are stored per pool, as there are many different HP pools and the individual ones are therefore required comparatively rarely, whereas 10,000 profiles are stored in the pools required to model the charging points of EVs, since there is less variance here (e.g., only one home charging pool exists for all home charging points).

The remaining assumptions concerning charging powers and power factors are identical compared to the Monte Carlo simulation described in section 3.1. The load profiles are as well determined in a Python environment and then imported to PowerFactory in order to perform a quasi-dynamic simulation.

### 3.2.1 Probabilistic Approach with Load Profile Pools and Only Most Critical Iterations

This calculation variant is identical to the one presented previously in section 3.2, with the only difference that a preselection of the iterations to be modelled is made here in order to be able to reproduce rarely occurring critical network states even with a smaller number of iterations.

The most computationally intensive part of the analyses using load profile pools is the import of the load time series and the load flow calculation in PowerFactory. The more iterations calculated here, the longer the entire simulation takes. In comparison, the load profile extraction from the pools that takes place beforehand in the Python environment can be carried out very quickly. Therefore, in this approach, for each grid connection point  $i \in \{1, \dots, N\}$ ,  $n$  stochastic load time series  $P_i^{(j)}(t)$  are generated by sampling from the predefined load profile pools, with  $j \in \{1, \dots, n\}$  denoting the iteration index. For each iteration  $j$  the aggregated active (peak) power across all grid connection points in the respective low-voltage grid area is computed as shown in equation (2) and (3).

$$P_{agg}^{(j)}(t) = \sum_{i=1}^N P_i^{(j)}(t) \tag{2}$$

$$P_{max}^{(j)} = \max(P_{agg}^{(j)}(t)) \tag{3}$$

$P_{agg}^{(j)}(t)$       Aggregated active power across all GCPs in kW

$P_i^{(j)}(t)$       Active power of GCP  $i$  in kW

$P_{max}^{(j)}$       Aggregated peak active power in kW

In order to reduce the overall computational effort while still depicting rare but critical system states, only the  $k \leq n$  iterations with the highest values of  $P_{max}^{(j)}$  are selected as described in equation (4).

$$K = \arg \operatorname{top}_k \{ P_{max}^{(1)}, \dots, P_{max}^{(n)} \} \tag{4}$$

$K$       Set of load profiles with the  $k$  highest peak loads

$P_{max}^{(j)}$       Aggregated peak active power in kW

Subsequent load flow calculations are performed exclusively for the selected set  $K$ . While this approach ensures that the most critical iterations in terms of total grid load (transformer load) are captured, these iterations do not necessarily correspond to the most critical states for individual line sections or nodes. Therefore, the required number of iterations  $k$  for reliable modelling results is further analysed (see section 5.1). The general procedure is summarized in Figure 4.

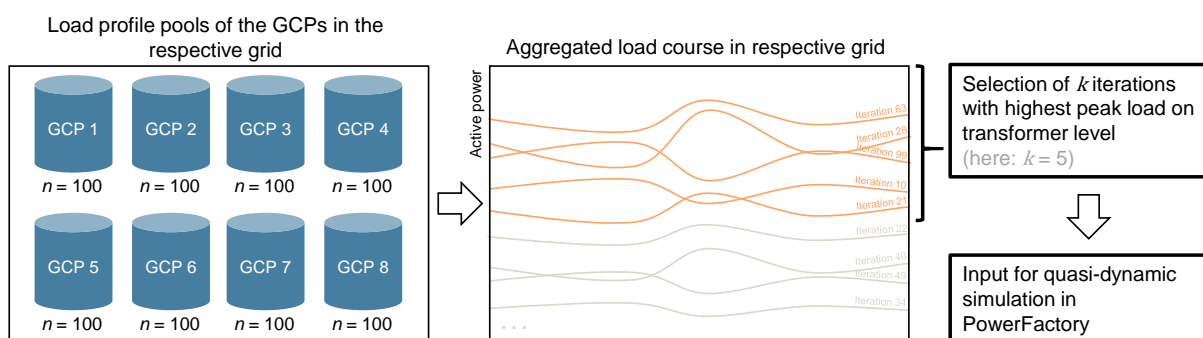


Figure 4: Illustration of the pooling approach with only considering the most critical iterations for modelling

### 3.3 Simultaneity Factor Approach

In this calculation variant, time series analyses are no longer carried out. Instead, the load estimate is based on simultaneity curves (simultaneity factors in dependency to the number of connected consumers) which result in static load values. The simultaneity curves are considered individually for all relevant load types. This allows the load contribution of a single load to be determined. Different times of the day (potential peak load times in the morning, at noon,

and in the evening) are examined. The load flow calculation itself is then performed in Power-Factory using the low voltage load flow analysis method. It should be noted that this calculation approach only considers active power and does not take reactive power into account. A more detailed description of this simultaneity factor approach is provided in [14].

## 4 Description of the Typical Network Areas Used for the Assessment

For the evaluation of the different calculation methods, typical low-voltage network areas are defined as example areas. Based on [1], three typical grids representative for urban areas are utilized here: an area with dense building structure and primarily residential use, an area with loose building structure and primarily residential use, and an area primarily used for commercial and retail purposes. These networks are all based on existing grid areas.

The load allocation represents a forecast for the year 2050, in which existing gas heating systems have been replaced by district heating, heat pumps, or other alternative technologies, and the entire passenger vehicle stock has been electrified. Further details of the load allocation and chosen scenario can be found in [14] (applied scenario: “Zielszenario”).

### 4.1 Grid with Dense Building Structure and Primarily Residential Use

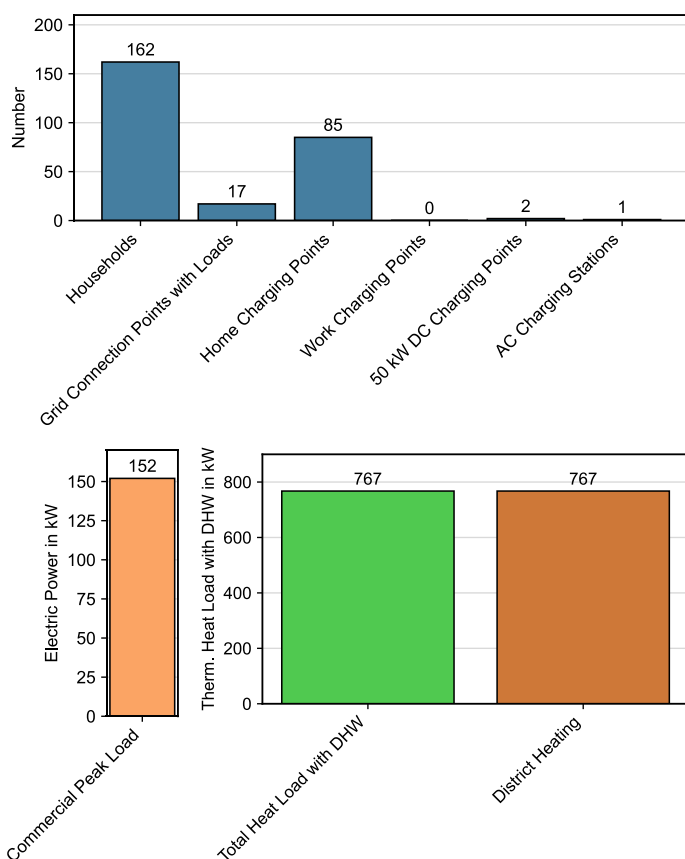


Figure 5: General grid information and allocated loads of the residential dense grid

This typical grid, consisting mainly of residential buildings in dense structure, is representative for about 35 % of urban grid areas and is therefore the most common grid type [1]. It supplies 162 households, 85 home charging points for EVs, one public AC charging station and two public DC charging points. The commercial peak load amounts to about 150 kW. The complete heating sector is being supplied by district heating (therefore no electric power demand at low-voltage level that needs to be considered due to heating), which is also typical for a grid in the central areas of a city. A summary of the supply structure is given in Figure 5. This network will be referred to hereinafter as “residential dense grid”.

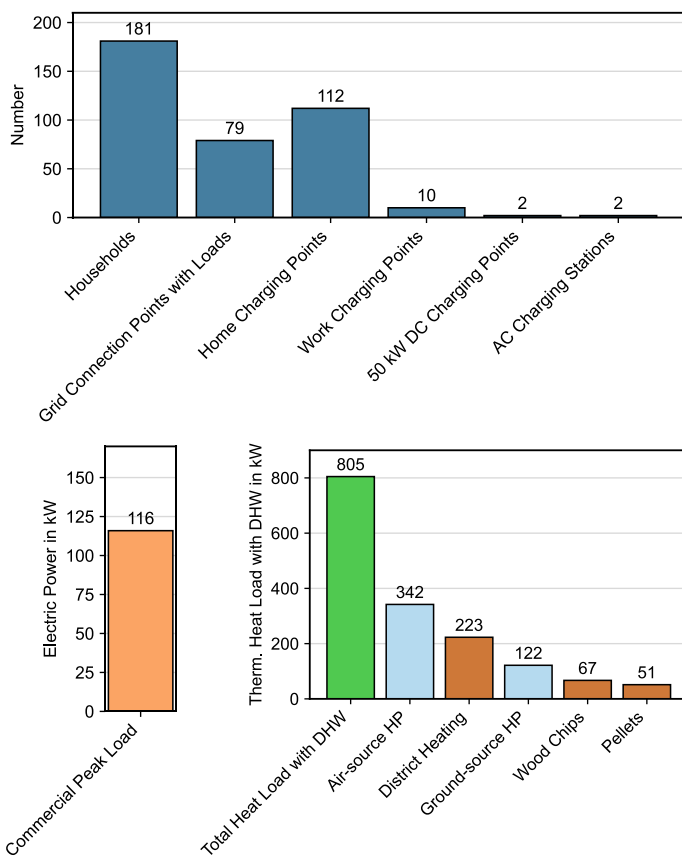


Figure 6: General grid information and allocated loads of the residential loose grid

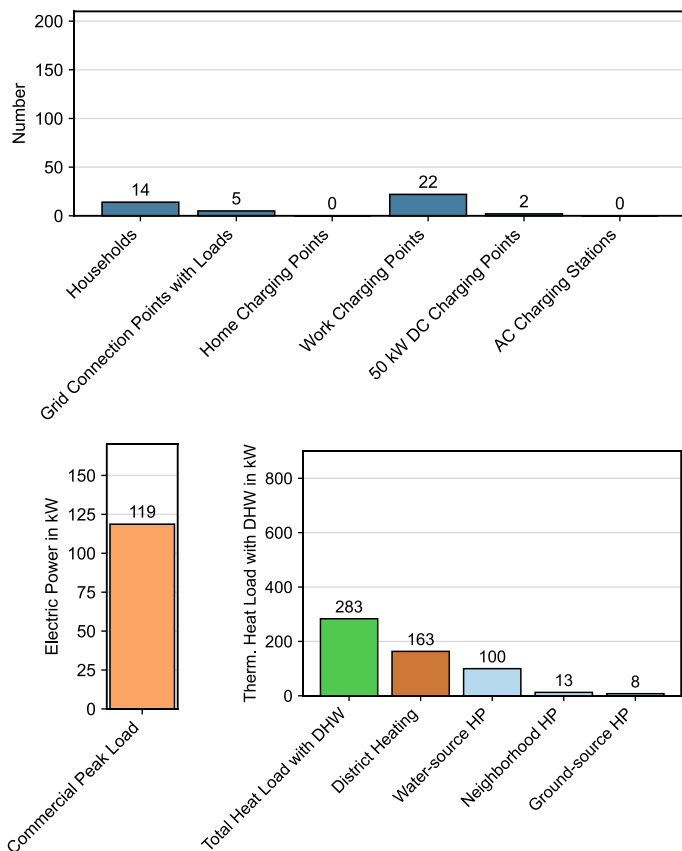


Figure 7: General grid information and allocated loads of the commercial grid

## 4.2 Grid with Loose Building Structure and Primarily Residential Use

This typical urban network, which mainly consists of residentially used buildings in a loose structure, is the second most common grid type (representative for about 22 % of the urban grids, c.f. [1]). 181 households are connected next to 112 home charging points for EVs, 10 work charging points, two public AC charging stations and two public DC charging points. The commercial peak load is 116 kW and in total around 60 % of an overall of around 800 kW of the thermal building heat load is being supplied electrically by decentral air-source and ground-source HPs, with air-source HPs accounting for the largest share of heat load. It shall be noted that in this network area, a comparatively high percentage of heat generation is based on wood chips and pellets (typically a lower percentage). Figure 6 summarizes the grids' supply structure. This network will be referred to as "residential loose grid" in the following.

## 4.3 Grid Primarily Used for Commercial and Retail Purposes

In order to not only analyse primarily residentially used grids, this network shall also be considered. It is primarily utilized for commercial and retail purposes (about 8 % of all urban network areas are represented by this grid type, see also [1]). Only 14 households are supplied here, as well as 22 work charging points for EVs and two

public DC charging points. The commercial peak load equals to 119 kW. In total 121 kW of an overall of 283 kW of the thermal building heat load is supplied by decentral electric heating solutions (various HP technologies, but no air-source HP systems). Figure 7 provides an overview of the key elements of the network's supply structure. This grid area will be further referred to as the "commercial grid".

## 5 Comparison of the Different Calculation Methods and Variants

The influence of the time resolution of the simulation, the number of iterations (analysis periods) examined, and the different calculation methods presented previously in section 3 shall be analysed in this section.

### 5.1 Effects of Time Resolution and Number of Analysis Periods

First the effects of varying the time resolution of the calculations and the number of periods analysed shall be addressed. For this purpose, the typical grid areas are examined first using the **Monte Carlo simulation** in order to generate the time-series load profiles and the quasi-

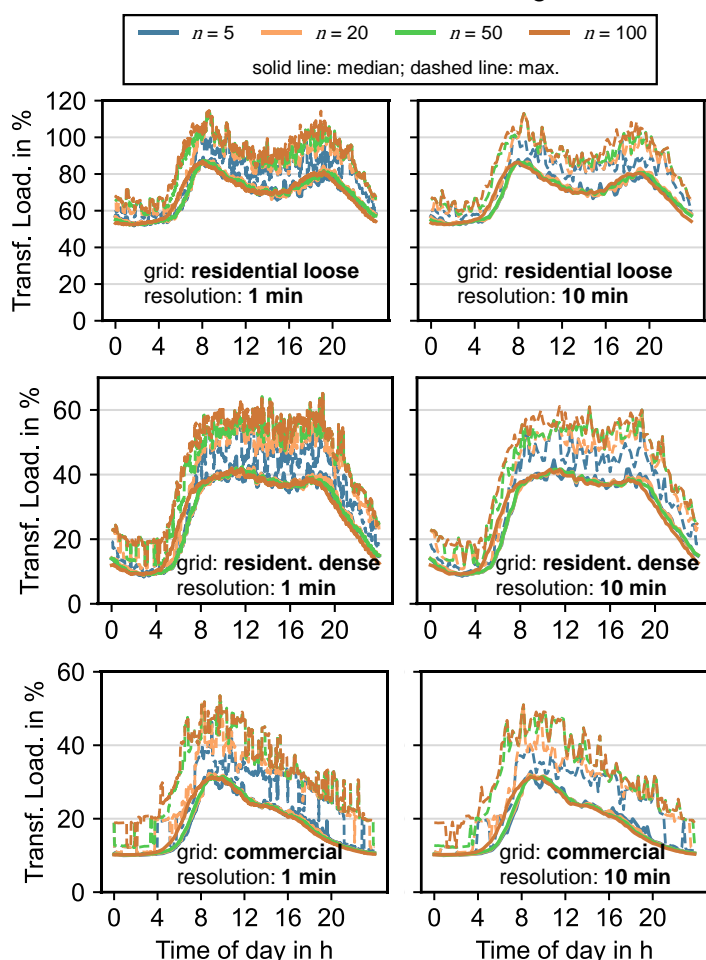


Figure 8: Results of transformer loading for different time resolutions and analysis periods

dynamic simulation in PowerFactory to calculate the resulting load flows (see also section 3.1). A one-minute resolution and a 10-minute resolution (which then represents the 10-minute average of power, currents, and voltages) are compared. In addition, a varying number of iterations of 5, 20, 50, and 100 is analysed. One iteration corresponds to one standard outdoor temperature period, which consists of two days (so e.g., with  $n = 100$ , a total of 200 days at standard outdoor temperature are considered). The results of the analysis are summarized in Figure 8 and Figure 9. In the box plots, the box itself represents the range from the first to the third quartile. The median is marked by the horizontal line. The whiskers above and below delimit the normal value range, with its boundaries deviating by a maximum of 1.5 times the interquartile range from the first to the third quartile of the distribution. Outliers are represented as dots. The results in one-minute resolution are shown on the left, and the results in 10-minute resolution on the right side of the graph. As expected the simulation results show a slightly lower equipment loading when using the 10-

minute resolution. The results in one-minute resolution are shown on the left, and the results in 10-minute resolution on the right side of the graph. As expected the simulation results show a slightly lower equipment loading when using the 10-

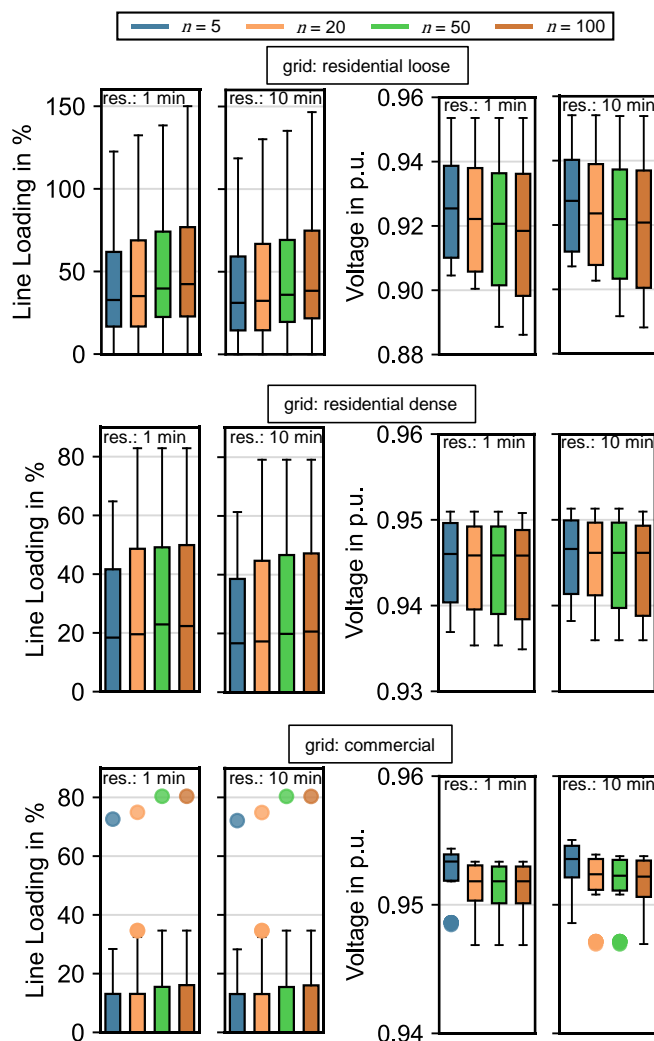


Figure 9: Results of max. line loadings and min. node voltages for different time resolutions and analysis periods

minute average, but the differences compared to the one-minute resolution are small. Because the 10-minute average value is decisive for the evaluation of voltage quality in accordance with DIN EN 50160, and since the 10-minute average values are further more practice-oriented and indicative for cables and transformers due to the existing thermal inertia as well, the 10-minute time resolution is chosen for subsequent analyses.

The effects of varying numbers of analysis periods are indicated by the different colours in the graphs (see also legend above). A more significant difference is evident here, whereby in general higher equipment loadings can be depicted with increasing iteration numbers  $n$ . This implies that using a small number of iterations may result in an underestimation of the load situation. While the differences in maximum equipment loading between five and 100 analysis periods (meaning 10 versus 200 analysis days at standard outdoor temperature) can be quite high, there

are no significant differences between 50 and 100 iterations anymore.

Figure 10 shows the resulting computation times for the different variants. For better comparability, the durations are normalized to one for each grid respectively, with one corresponding to the duration of the variant with the longest calculation time. The absolute computation times depend heavily on the available computing power and the efficiency of the implemented code, which is why the normalized representation is chosen to enable a basic comparison of performance. It has to be noted that the utilization of the 10-minute average values only affects the calculation times in PowerFactory (144 time steps per day compared to 1,440 time steps at a 1-minute resolution), as the Python models applied for the load profile generation were designed for a one-minute resolution.

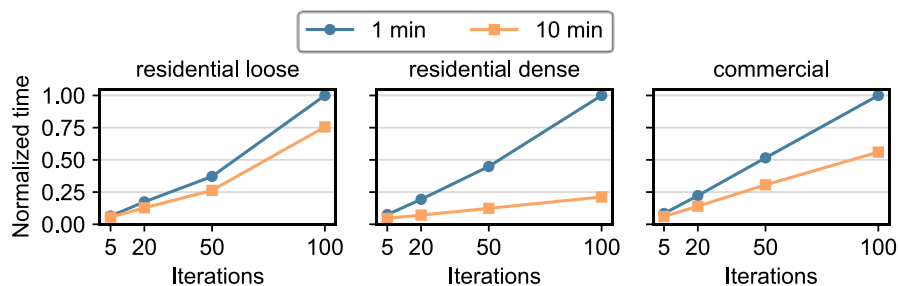


Figure 10: Normalized computation time of the different calculation variants

It becomes clear that the resulting durations are highly dependent on the grid area and the underlying consumption

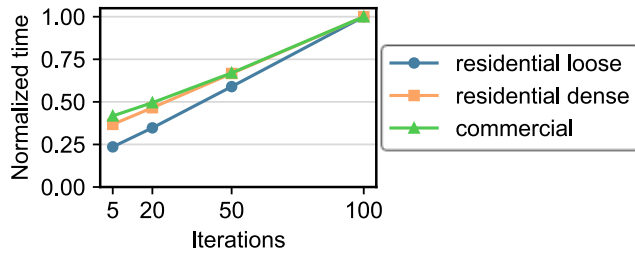


Figure 11: Normalized computation time of varying numbers of analysis iterations using the pooling approach with only consideration of the most critical iterations (10-min. resolution)

structure. The example of the residential loose grid shows that switching from 1-minute resolution to 10-minute resolution only enables a comparatively small improvement in performance, whereas on the other side a comparatively large improvement can be achieved in the residential dense grid. The reason for this lies primarily in the supply structure of the networks. In particular due to the time-consuming modelling of the electrical heating systems in the residential loose grid, the majority of the computation time is spent in the Python environment for the load profile generation. In comparison, in the case of the residential dense grid, the modelling of the electrical heating systems can be completely spared, since the entire grid area is supplied by district heating. Therefore, the majority of the calculation effort here is spent on importing the load profiles into PowerFactory and performing the quasi-dynamic simulation there, which is why a significant performance improvement can be achieved by increasing the time resolution to 10-minute averages. However, as a general principle, the higher the number of periods examined, the longer the calculation time, and the larger the time resolution, the shorter the calculation time. If, for example, the variant of 100 iterations with a one-minute resolution are compared with the variant of 50 iterations in a 10-minute resolution, it can be seen that the latter requires only about 25 % of the calculation time,

which can be an important factor when there are a large number of grid areas to be analysed.

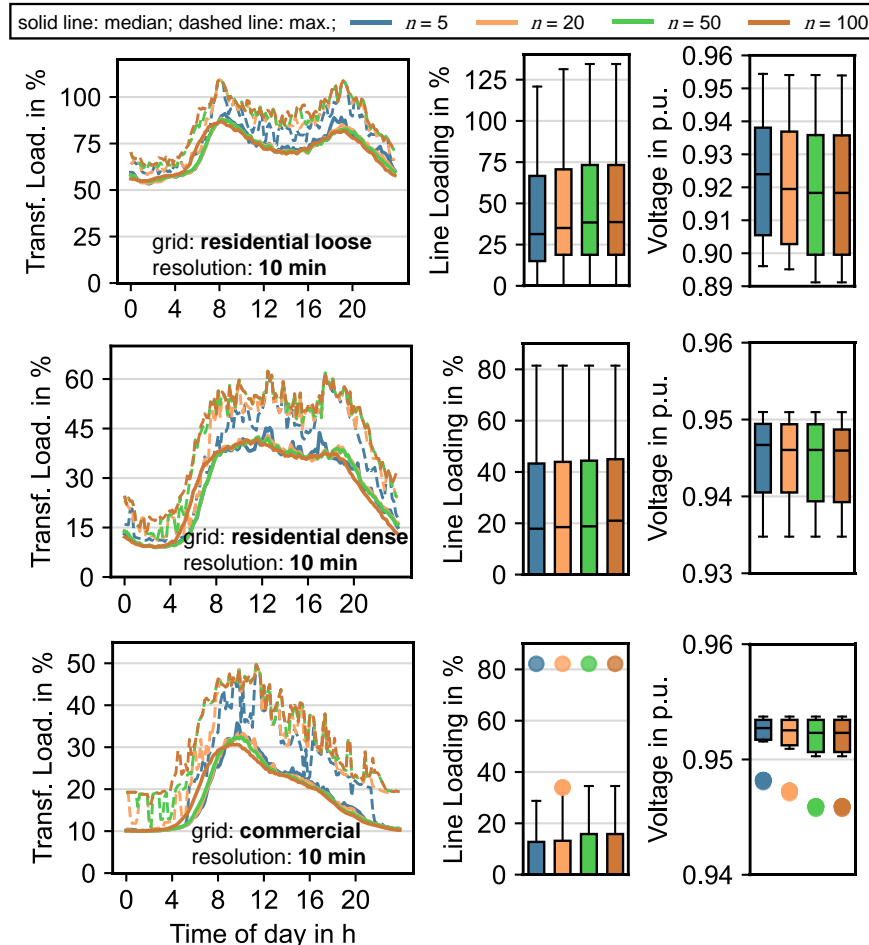


Figure 12: Influence of varying numbers of analysis periods using the pooling approach with only consideration of the most critical iterations

In the following, the influence of varying the number of iterations (analysis periods) using the **probabilistic approach with load profile pools and only consideration of the most critical iterations** presented in section 3.2.1 shall be examined. A 10-minute resolution is chosen. The resulting computation times are displayed in normalized form (one corresponding to the duration of the longest calculation time per

grid) in Figure 11. It can be seen that already a comparatively high amount of time is required for a small number of iterations and that, e.g., there is no significant difference between considering five and 20 analysis periods.

The modelling results are summarized in Figure 12. Since this approach involves preselecting the analysis periods and only considering those with the highest load (at transformer level), comparatively accurate results can be achieved even with a smaller number of analysis iterations. The maximum load on the transformer can be depicted using the selected approach even with a low number of iterations. In the case of line loading and node voltages, increasing the number of iterations can achieve an increase in accuracy, as the maximum load on the individual line sections and nodes does not necessarily coincide with the time of maximum load at the transformer. However, the differences are smaller than in the Monte Carlo variant (see Figure 9), and no significant difference is apparent between 50 and 100 analysis iterations anymore.

## 5.2 Comparison of the Different Calculation Methods

Now the calculation methods presented in section 3 shall be compared with each other. All analyses are carried out using a 10-minute resolution. In the Monte Carlo simulation (Classic MC), the Monte Carlo simulation with simplified heating system modelling (MC + SHSAP), and the probabilistic approach with load profile pools (Pooling), 100 standard outdoor temperature periods (so 200 days) are considered in each case. In the case of the probabilistic approach with load profile pools and only considering the most critical iterations (Pooling + only 20 crit. iter.), only the twenty

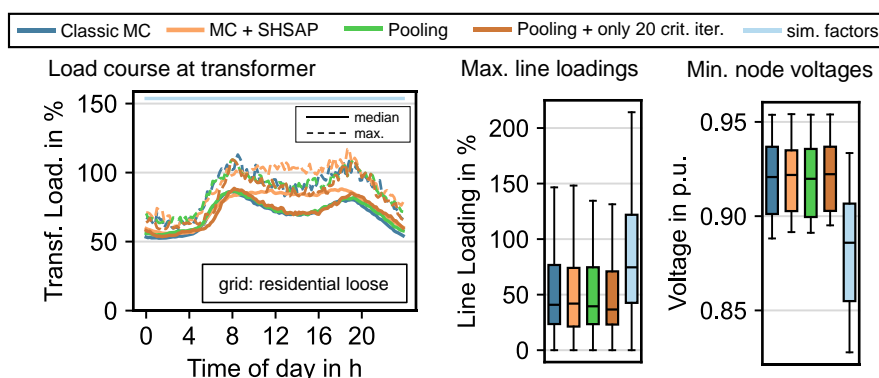


Figure 13: Results of the different calculation methods for the residential loose grid

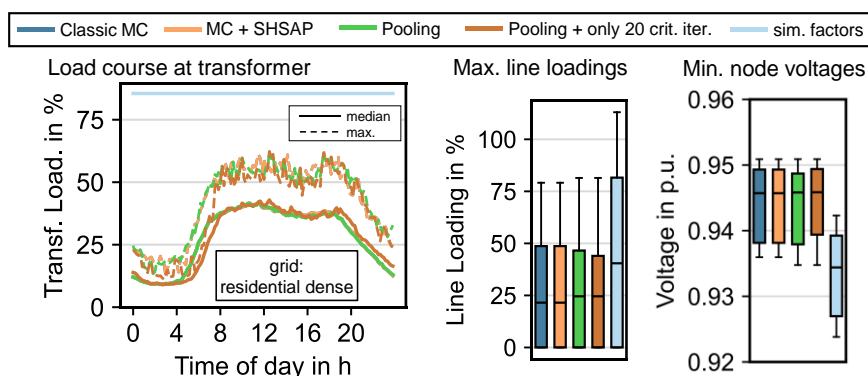


Figure 14: Results of the different calculation methods for the residential dense grid

periods of the pooling approach are considered in which the aggregated grid load was highest (see also description in section 3.2.1). With the simultaneity factor approach (sim. factors), only a static value is determined, rather than a time-resolved value over different periods.

The results are summarized for the three representative network areas in Figure 13 (residential loose grid), Figure 14 (residential dense grid) and Figure 15 (commercial

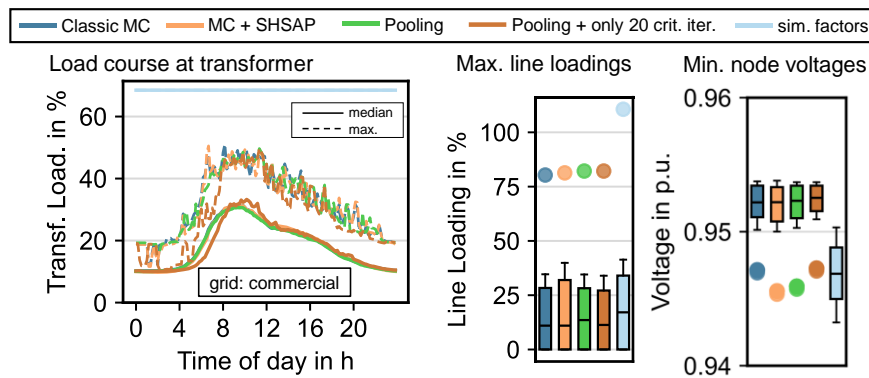


Figure 15: Results of the different calculation methods for the commercial grid

grid). In general, it can be seen that the differences between the calculation variants Classic MC, MC + SHSAP, Pooling, and Pooling + only 20 crit. iter. are comparatively small. In the case of Pooling + only 20 critical iterations, the line loadings are slightly lower and the node voltages are slightly higher than in the other variants, but still remain within a very similar range. In the MC + SHSAP variant, there are no differences to the Classic MC approach in the residential dense grid due to the lack of electric heat generation there (see also section 4.1). In case of the residential loose grid, deviations in the MC + SHSAP variant become apparent particularly at midday. This can be explained by the high share of air-source HPs there: since the simplified heating system model only determines a constant average electrical power demand based on the overall system efficiency of the HP (see [3]), the higher coefficient of performance of the HP (and thus the resulting lower power demand) caused by the higher ambient temperatures during midday and afternoon is not taken into account here. However, when estimating the maximum loadings of the operating equipment, a very similar result to the Classic MC variant can still be obtained here in terms of both equipment loadings and node voltages. Compared to the other variants, the utilization of the sim. factors approach leads to a more conservative estimation of the resulting equipment loadings. By using simultaneity curves for a simplified load estimation, only static worst-case load values are considered here, which results in a comparatively high loading of the operating equipment.

A comparison of the computation time of the different calculation methods is shown in normalized form (one equals to the duration of the longest calculation time per grid) in Figure 16. It can be seen that the Classic MC variant requires by far the longest computing time. The new probabilistic calculation for each load and analysis period results in long calculation times, in particular due to the detailed modelling of the electric heating system.

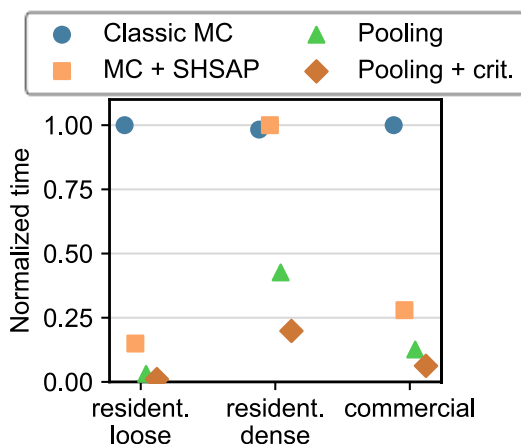


Figure 16: Normalized computation time of the different calculation methods (10-min. resolution)

particular due to the detailed modelling of the electric heating system. If the simplified heating system model is utilized instead, the computing times can be significantly reduced (with the exception of the residential dense grid, in which no electric heating systems exist). The pooling variants can result in further significant time savings in the calculation, with the Pooling + only 20 crit. iter. variant generally requiring the least amount of time among the compared variants. However, it should be noted that an initial investment of time is required to create the load profile pools. If only a small number of networks or a low number of

periods are to be examined, this approach is unlikely to be cost-effective due to the high initial investment. Still, it is a very good way of reducing the computing effort required for a large number of networks or a high number of iterations. For a better contextualization: In the time required purely for the creation of the load pools for the three network areas according to the methodology described in section 3.2, the complete network calculations could already be performed 2.4 times using the Classic MC variant (10-minute resolution, 100 iterations). However, since the number of clusters required decreases significantly in relative terms as the number of networks to be analysed increases<sup>1</sup>, this approach is still very recommended for large network or high iteration numbers.

It should generally be noted that the information on runtime is indicative and is intended to enable an overall comparison. There is still further potential for optimization in terms of code implementation for the different calculation variants, which could also alter the depicted ratios. The sim. factors approach is outside the scope of time recording, as the approach described in [14] is designed to carry out large-scale analyses with a high number of network areas and can hardly be broken down into individual network areas. Here, an initial investment for creating the required simultaneity curves must also be taken into account, but overall – especially for a large number of networks – the shortest runtime can be expected here, as no time series calculation is performed and only a static value is determined for the calculations.

## 6 Conclusion and Outlook

This work compares simplified and detailed calculation methods for forecasting future load development in urban low-voltage grid areas under advancing sector coupling. Using three representative urban low-voltage grid areas (a residential grid with dense building structure, a residential grid with loose building structure, and a commercial grid) and a 2050 target scenario, the study analyses different calculation methods, time resolutions and number of analysis iterations. It compares the modelling accuracy in terms of transformer loading, line loading, and node voltages, as well as the computational effort as a key constraint for large-scale applications by distribution system operators.

The results indicate that a 10-minute time resolution is a practical and sufficiently accurate choice for quasi-dynamic load flow analyses: compared to a 1-minute resolution, the reduction in peak equipment loading is small, while computation times can drop substantially. The 10-minute time resolution aligns further well with operational practice (consideration of the thermal inertia of transformers and cables) as well as the voltage quality assessment which is also based on 10-minute averages.

Regarding the number of analysed periods, increasing the iteration count enables the capture of less frequent critical states, but the benefit saturates: differences between low and high iteration counts (e.g., five vs. 100 iterations) can be significant, whereas no larger improvements in accuracy are observed between 50 and 100 iterations anymore for the investigated grids using the Monte Carlo simulation approach. Consequently, around 50 iterations (here:

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<sup>1</sup> If only the three representative network areas analysed here are considered, an average of 17.7 clusters is needed per network area. If all network areas in Munich are examined (> 4,000), only an average of about 0.6 clusters is required per network area.

100 days) represent a reasonable default compromise between robustness and runtime for detailed probabilistic studies. When applying the load profile pooling approach with only considering the most critical iterations, reliable results can also be achieved with even fewer iterations.

Table 1: Concluding comparison of the different calculation variants

| Calculation method         | Modelling results   | Computational complexity                       |
|----------------------------|---|--|
| Classic MC                 | Benchmark for the other approaches: Time-resolved simulation with reliable modelling of critical network states when using high iteration numbers                         | no initial effort, high operational effort     |
| MC + SHSAP                 | Similar results regarding maximum equipment loading; moderate differences visible in the shape of the resulting load profiles in grids with high shares of air-source HPs | no initial effort, medium operational effort   |
| Pooling                    | Very similar results to Classic MC – when applying the same number of analysis iterations   | high initial effort, medium operational effort |
| Pooling + only crit. iter. | Very similar results to Classic MC – also with a lower number of analysis iterations  | high initial effort, low operational effort    |
| Sim. factors               | Conservative (overestimating the equipment loading in comparison with the other approaches) and static peak load estimate without time-resolved results                   | high initial effort, low operational effort    |

When comparing the individual modelling approaches, the Classic Monte Carlo approach is computationally most demanding, mainly because new load profiles are probabilistically generated for each consumer and iteration (particularly costly for detailed HP modelling). Replacing detailed HP modelling with the simplified heating system model yields a strong runtime reduction while preserving very similar results for maximum equipment loading compared with the Classic Monte Carlo approach. Deviations are mainly visible in the resulting shape of the load profile (at midday higher load in grids with a high share of air-source HPs). For planning questions focused on worst-case loading of the operating equipment, using the simplified heating system model therefore appears to be a robust modification, especially when computational resources are limited.

The presented pooling approaches (utilization of pre-generated load profile pools) offer a particularly attractive solution. Both, the Pooling approach and the Pooling approach with only consideration of most critical iterations reproduce the Classic Monte Carlo results with comparatively small deviations for transformer loading, line loading, and node voltages, while substantially reducing the computational effort for analyses of large network or high iteration numbers. The analysed “Pooling + only 20 critical iterations” variant is especially efficient: by pre-selecting iterations with the highest aggregated peak load at transformer level, it captures transformer-relevant extremes already with few analysis iterations. However, because the highest loading for individual line sections or node voltages minima do not have to necessarily coincide with the transformer peaks, accuracy can still benefit from increasing the number of

iterations. The recommended number of iterations here lies between 20 and 50, as there are no longer any relevant differences in result between 50 and 100 iterations.

In contrast to the other approaches, the simultaneity factors approach provides a conservative estimate because it relies on static peak assumptions rather than time-resolved probabilistic load series. This makes it well suited for fast, large-scale evaluations and for deriving robust expansion needs where a conservative bias is acceptable – yet it may overestimate loading compared to the time-series based probabilistic methods. The comparison of the different calculation variants is summarized in Table 1.

Practical recommendations for distribution system operators can therefore be derived as follows:

- For the analysis of a small number of networks or a one-time detailed evaluation, the Classic Monte Carlo (if necessary in combination with the simplified heating system model in areas with high shares of electric heating systems) is recommended.
- For a large number of networks and/or various different scenarios, the pooling approach with only consideration of the most critical iterations becomes highly attractive despite an upfront investment to generate the load profile pools – especially because the relative pool creation effort decreases strongly with scale.
- The simultaneity factors approach is an efficient conservative modelling tool for quickly identifying critical networks or for network planning at an initial stage; networks identified as critical can then be analysed further utilizing the probabilistic variants.

The findings of this work are now being taken into account for large-scale investigations of real urban grid areas in the “Grid for Electrification” [15] research project. In [14], for instance, the grid expansion requirements due to sector coupling in the urban distribution grid of Munich are determined using the simultaneity factor approach.

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