Impact of Operation Strategies of Large Scale Battery Systems on Distribution Grid Planning in Germany

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Abstract

Due to the increasing penetration of fluctuating distributed generation electrical grids require reinforcement, in order to secure a grid operation in accordance with given technical specifications. This grid reinforcement often leads to over-dimensioning of the distribution grids. Therefore, traditional and recent advances in distribution grid planning are analysed and possible alternative applications with large scale battery storage systems are reviewed. The review starts with an examination of possible revenue streams along the value chain of the German electricity market. The resulting operation strategies of the two most promising business cases are discussed in detail, and a project overview in which these strategies are applied is presented. Finally, the impact of the operation strategies are assessed with regard to distribution grid planning.

Keywords: grid planing, distribution grid, large scale batteries, community storage, primary frequency control.

1. Introduction

The energy system in Germany is currently changing. In the past, electrical energy was injected by large power plants into the transmission system (220 kV and 380 kV) to cover long distances. It was then delivered to costumers via distribution (smaller) grids (1 kV to 110 kV). Since the German Federal Government decided to withdraw from the nuclear energy programme and to reduce the greenhouse gas emissions in order to mitigate climate change, the expansion of renewable energy sources was subsidised by introducing the German Renewable Energy Act (EEG) in 2000. This led to a tripling of the share of renewable energy in the German electricity mix from 7 % in the year 2000 to 25 % in the year 2013 [1]. As a consequence, the sinking levelised cost of electricity (LCOE) of renewable energy sources (RES) led to grid parity. [2]. This trend will probably continue as the German Federal Government committed itself to a RES ratio of 80 % of the gross electricity production in the year 2050 [3]. In contrast to conventional power plants, RES are

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mainly realised as distributed generators (DG), as defined by [4, 5]. Due to their relatively small installed nominal power they are mainly connected to the distribution grid at medium voltage (MV) and low voltage (LV) levels [6, 7]. For example, 80 % of photovoltaic (PV) power plants in Germany are connected to the LV grid [8]. Due to this, the nominal DG power installed in the distribution grid surpassed the power installed in the transportation grid in 2010 [9]. Furthermore, the DG are distributed very inhomogeneous in Germany with wind power plants in the north and photovoltaic systems in the south [10]. This, and the fact that the power feed-in of DG is not necessarily simultaneous to the local load demand, results in a transformation process of the distribution grids. Formerly they were characterised by the consumption whereas now the reverse power flow becomes increasingly common. This means that in some moments of the year there is a power flow from the distribution grid to the transportation grid [11]. As German electricity grids are planned to work uni-directional with a power flow from high to low voltage levels this could lead to several problems. For example the protection concept is designed such as to work for an uni-directional power flow and may not work in a bi-directional way [12]. Furthermore, power quality issues can arise. In some grids the maximum possible PV penetration rate is reached as DG are often installed in rural grids [13]. Therefore, an additional installation of DG is often followed by grid reinforcement in order to solve over-voltage and equipment over-loading issues. The drawback of this traditional grid planning procedure is large investment in infrastructure with a low utilisation rate. Historically, network extension planning has been based on maximum load scenarios, but in the case of a high penetration with DG the grid is dimensioned to deal with maximum generation [14]. In Germany, the number of hours in which PV-systems feed more than 90 % of their nominal power into the grid is below 100 hours a year [15]. Due to this, traditional grid planning may cause inefficient grid operation and higher grid utilisation fees that have to be borne by the general public (cost increase of 9,2 % from 2008 to 2014) [16]. As in [17] predicted, this will lead to a linear cost increase for DG induced grid reinforcement due to over-voltage and over-loading issues of 331 EUR/ kW until 2030. The cost can be designated to different voltage levels (400V:13 % / 1 kV-36 kV:29 % /60 kV − 380 kV: 58 %). Therefore, the impact of different operation strategies of microgrids [18], electrical vehicles [19] and residential storage systems [20, 21] to increase the hosting capacity of DG in distribution grids have been analysed by the authors. Although [22] provides an overview of (large scale) energy storage technologies suitable for wind power application, the implications of the operating strategies as for example voltage control for distribution grid planning have not been analysed in detail. Extending the previous work of the authors, this paper gives an overview and evaluates alternative possibilities to traditional DG induced grid extension with large scale battery storage systems (BSS). As in most cases, this alternative turns out not to be profitable, if the BSS's only purpose is to mitigate traditional grid extension [14] additional revenue streams have to be taken into account. Therefore, the objectives of this paper are to review additional applications for BSS in the German electricity market in order to combine them with the task of mitigating grid extension caused by DG and evaluate the impact of the resulting operation strategies on traditional and new approaches of distribution grid planning. The paper is structured as follows: In section 2 the legal framework for the operation of distribution grids in Germany and the challenges that arise with integration of high shares of DG are described briefly. Section 3 covers traditional distribution grid planning and in section 4 new grid reinforcement planning methods are presented. A brief overview of different BSS applications and their possible profit margins for the German energy market is presented in section 5. In the same section, the implementation of large scale battery systems in distributions grids is discussed. The focus lies on BSS that apply self-consumption maximisation and primary control reserve, due to their economical relevance, as well as the possible impact on the grid planning. Finally, the conclusions are summarised in section 6.

2. Legal framework, arising challenges and possible solutions for DG and BSS connected to distribution grids in Germany

2.1. Legal framework for the operation of distribution grids

According to the German Energy Act (EnWG) section 14(1) [23] the grid operators are legally bound to ensure a safe and stable energy supply. Especially the power quality issues of over-loading of cables and transformers as well as over-voltage are of major interest. The parameters that should fulfilled regarding over-loading of transformers and LV-cables are defined in DIN EN 60076-2:2011 [24] and DIN VDE 0276-603 [25], respectively. Table 1 shows the load factors of the rated apparent power S_r for different components according to [17] under normal operation conditions that are defined in [26]. For the heavy load flow (HLF) and reverse power flow (RPF) different maximum load factors apply. This is due to the different shape of the profiles in both cases. Furthermore, the (n-1)-criterion as defined in [27] and further specified in [17] applies for MV-cables and HV/ MV transformers for the load case. In the case of a HLF for MV-cables and HV/ MV transformers [17] sets the maximum loading to 120 %. For all other components and scenarios it is set to 100 %. Nevertheless, the maximum loading of MV/ LV transformers depends not only on the profile but is also not consistent in the literature: it ranges from 150 % for oil immersed transformers only[28, 29] to 120 % [30, 31] and 100 % [17] for all kind of transformers in the case of a RPF caused by PV systems .

[Table 1 about here.]

Voltage characteristics of electricity in distribution grids are defined in [26]. The most important restrictions are that the frequency has to be kept at 50 Hz ±1 Hz and the 10−minute RMS average of the voltage at the point of common coupling (PCC) has to be kept with in an interval ±10 % of the nominal voltage. To ensure this two technical specifications for DG quantify the permitted voltage rise of 2 % in the MV [32] and of 3 % in the LV, respectively [33]. These technical specifications apply if the MV or the LV are calculated separately, otherwise these thresholds don‘t have to be considered. Furthermore, all generators connected to the electrical grid have to comply with the specifications of [34], [35] and [36], respectively. Furthermore, the technical note [37] has to be considered for BSS connected to the LV.

The technical restrictions for over-voltage and over-loading are commonly used to determine the hosting capacity, as defined in [38], to integrate DG into existing grids. An exhaustive international overview of the main technical issues limiting the hosting capacity for DG of distribution feeders is given in [39].

2.2. Challenges and solutions for electrical grids with fluctuating feed-in of renewable energies

In this subsection the challenges that arise from the integration of high shares RES into the electrical grid are discussed. The increasing penetration of DG has, among other issues, led to the following [39, 40, 41]:

For distribution grids in particular:

- Thermal over-loading of network equipment
- Voltage rise
- Increased fault levels, especially for MV grids
- Power quality issues
- Impact on grid protection due to RPF
- Effect on the operation of voltage regulators and tap changers because of RPF
- Impact on grid losses

For the whole electrical system:

- Increased demand of control power
- Increase of transmission line bottlenecks
- Decreasing spinning reserve

The most important challenge in distributions grids on an international level is due to over-voltage issues [39]. In Germany for example, 80 % of the grid reinforcement is due to over-voltage issues in distribution grids [42]. Besides grid reinforcement, ancillary services have to be provided by generators and loads to cope with these issues. These services are defined in [43] and classified as follows for normal operation conditions:

- Frequency control
- Voltage control

- Remote automatic generation control
- Grid loss compensation

All these ancillary services can be provided by DG and in particular by BSS [44]. Therefore, the technical and economic applications of BSS are analysed hereafter in order to supply ancillary services and as an alternative to traditional grid reinforcement.

3. Traditional distribution grid planning

Although, there are different guidelines for distribution grid planning on a national [45]and an international level [46], as well as recommendations like [47] , every DSO has a different planning process because of the different characteristics of each distribution grid and DSO [48]. To standardise the different planning approaches a study was conducted that summarises the methodology of 17 DSO covering more than 50 % of all distribution grids in Germany [17] and which can be regarded as the state-of-the-art approach. Fig. 1 describes the conventional distribution grid planning schematically:

[Fig. 1 about here.]

One problem of this approach lies in the input data, since the LV load is usually not measured and has to be estimated. The estimated LV load may be gained from the (measured) annual maximum load of the secondary transformers [49], the rated power of these transformers [50] or structural data as the degree of electrification or population density [49, 45]. Also, approaches employing combinations of these datasets are possible and described in [17]. On the generation side the rated power of the generators are usually well known and published [51].

To evaluate whether a certain threshold is reached (as described in section 2) a power flow calculation is conducted in which the power of the load and the generator are adjusted to certain worst case scenarios, specified in subsection 3.1. If a threshold is passed, the grid will be reinforced according to the methodology described in subsection 3.2.

3.1. Assumed scenarios - worst case parameters

Distribution grids are traditionally planned in a deterministic manner [46]. The traditional scenario to conduct a power flow only considers maximum demand, whereas the generation is assumed to be constant. As aforementioned, the higher penetration rate of DG leads to two worst case considerations: the heavy load flow (HLF) and the reverse power flow (RPF) scenario. On an international level they are parametrised according to [46]:

1) Heavy load flow: Max load; no generation.

2) Reverse power flow: Min load; max generation.

These extreme parameters do not consider the time variability of demand and generation. Thus, a simple probabilistic determination of the worst case scenario parameters that covers all possible grid states for Germany sets the scenarios closer to the reality. For loads, this scenario parameter is called coincidence factor and is defined in [46] as the average power absorbed related to the installed power. For generators, this factor is referred to as diversity factor by [52], and is defined as the quotient of the actual and the installed capacity. To quantify the coincidence and the diversity factor taking into account the simultaneity of generation and consumption, several studies have been conducted [7, 17, 53, 54]. The diversity factors of [7] apply for ten generators of the same type. The same study presents that diversity factor differs if the correlation between the generators is taken into account. The results are listed in Table 2 and Table 3.

[Table 2 about here.]

[Table 3 about here.]

The coincidence and diversity factors all apply to the maximum/rated power of the generators and loads. In case of PV this factor refers to the installed module power P_{STC} [53, 54]. In the reverse power flow case the factor for the load of the MV is higher, as higher blending of the stochastic behaviour of the loads is taken into account. Some bigger costumers/loads have their own secondary transformer and are connected directly to MV (C. load). The maximum power of these loads can be assumed as 40 % of the rated apparent power $S_{r,t}$ of the secondary transformer [55]. Based on experience, these simple worst case parameters cover all possible grid states. These worst case scenarios are therefore commonly used, e.g. in [56, 57, 17], as this method provides a high level of reliability without measurements in the LV [45]. The likelihood of these extreme grid states however, is not considered with this practice, and may never occur in reality [58]. Furthermore, no time interdependencies of the assets are considered. As a consequence, the distribution grids tend to be over-dimensioned. Thus [59] and [46] claim that new planning approaches should be taken into account as they may use infrastructure more efficiently [47], as well as avoid redundant investments and minimise O&M costs [60]. There are plenty of different approaches to come to a more realistic assessment of the scenario parameters, as for example [55, 52, 61].

In general, there is a wide field of different new planning approaches for different applications which are analysed in subsection 4.1.

3.2. Grid reinforcement methodology

Hereinafter the methodology of grid reinforcement for distribution grids, especially for low and medium voltage grids, is described. The methodology is depicted in the figures for radial grid structures in the

LV and for open ring structures in the MV. Nevertheless, these methodologies are transferable to other grid topologies and can be considered as state-of-the-art in Germany [17]. As described before, triggers for grid reinforcement are either local over-voltages or over-loadings of a cable or a transformer. First, the over-loading measures are implemented, then another load-flow is conducted. If there are still over-voltage problems in the grid, the measures to solve these apply.

Methodology for low voltage grids:

As depicted in Fig. 2, an over-voltage is solved by installing a parallel cable (type see Table 4) from the distribution substation to the next distribution cabinet over 2/3 of the line length. A critical over-loading of a line is solved by installing a parallel line till the next distribution cabinet, starting to search from half of the line on.

[Fig. 2 about here.]

If more than one line is affected, as shown in Fig. 3, all affected lines are divided at the distribution cabinet that lies closest behind one half of the line. The lines of the second half are connected to a new secondary substation. The rated apparent power $S_{r,t}$ of the additional MV/LV transformer is the same as the one that was formerly feeding the entire LV-grid. If there is an over-loading in a transformer and its apparent power $S_{r,t} \leq 400\,kVA$, it is replaced by the next bigger standard transformer (630 kVA). If the over-loading is not solved, a parallel 630 kVA transformer is installed.

[Fig. 3 about here.]

Methodology for medium voltage grids:

Similar to the LV a parallel line is installed in the case of over-loading or over-voltage. In case of over-voltage the length of the new line is 2/3rd of the length of the affected feeder, whereas for over-loading the parallel line is installed between the primary substation and the DG that causes the trouble (see Fig. 4). It applies for both measures that no secondary substations are installed on the parallel MV line which is connected to the bus bar of the primary substation. At the connection points an additional breaker is installed in the affected feeder.

[Fig. 4 about here.]

If the parallel cable does not solve the issue, a new MV ring is installed according to Fig. 5. By this measure the critical part of the affected open MV ring is transferred to two uncritical open MV rings by separating the DG that causes the problems with a parallel MV line. The costs for the earthworks apply only once, as it is assumed that both lines share the same trench.

[Fig. 5 about here.]

If the HV/MV transformer is over-loaded it is replaced with a 40 MVA transformer. If the over-loading still remains a parallel 40 MVA transformer for the same feeder is installed. In case all the aforementioned measures do not solve the problems, a new primary substation is installed as depicted in Fig. 6. In this case, the placement of the new substation and new breakers is done manually in order to solve all occurring issues in the MV-grid manually.

[Fig. 6 about here.]

Other studies [62, 63, 64, 30, 31] suggest slightly different approaches. For example [62, 63, 31] regard low voltage exclusively, whereas [64] focuses only on the medium voltage and [30] considers both voltage levels. Another difference in [62, 31] is that the new parallel line is installed from the secondary transformer to the distribution cabinet closest to the critical node within the feeder.

According to [17, 62, 31] all new lines are supposed to be underground cables, instead of overhead lines due to the higher acceptance of the general public. For an easier automation the reinforcement equipment is standardised but differs from case to case as shown in Table 4.

[Table 4 about here.]

According to [13] who conducted a statistical analysis of distributions grids in southern Germany, the NAYY $4x240mm^2$ is the most commonly used cable type in LV (36 % in rural grids, 84 % in villages and 38 % suburban grids) and is used twice as often as any other cable type.

4. New planning methods and definitions for BSS

4.1. New planning methods for integrating DG and BSS in distribution grids

The aim of the reviewed studies in this section is to determine, besides other network parameters, the optimal number, location and size of DG and BSS units. This is achieved by optimising the total capital expenditures (CAPEX) and operational expenditures (OPEX) including DG and BSS. Several objectives have been pursued via this optimisation of DG integration in distribution grids. Some of the most common objectives are: minimisation of energy losses, maximisation of DG capacity or energy via sizing and allocation of DG, minimising curtailment losses, minimising costs, as well as the minimisation of the grid reinforcement cost associated with DG [65]. The planning process can be described as a non-linear mixed integer optimisation problem. There are several comprehensive reviews for new distribution grid planning approaches. While [66, 67, 68] describe and classify the planning approaches generally, [65, 69, 70] concentrate on DG integration. Hereafter, the criteria and definitions as well as the three-level tree-structure according to [66] are used to classify the planning methods used in a selection of reviewed studies listed in Table 5.

According to the first level of the tree-structure, all methods can be divided into models with or without reliability considerations. In planning models without reliability features the grid is operated under operational constraints. The aims of planning optimisations are minimising CAPEX of substations, feeders or feeder branches (assets), minimising the costs of capacity upgrades of the existing facilities, as well as minimising the OPEX and the energy losses.

In the second level, the models may or may not include uncertainty considerations. In contrast to deterministic planning, uncertainty models consider the unpredictability of future load demand and generation at the design stage. The reliability considerations may be considered in the planning and can be incorporated either under normal conditions or under contingency conditions. To include the maximum network reliability under normal conditions, a reliability objective function minimising the expected outage cost or expected annual non-delivered energy is added to the other objective functions. In order to include predefined fault/ contingency conditions an objective function similar to the aforementioned reliability objective function is employed.

The third level categorises all types of optimisation models depending on the type of (decision) variables and objectives. There are (a) mixed-integer (b) discrete and (c) continuous models. Commonly, integer variables in distribution system planning problems are used for decisions on whether or not new assets are installed or existing equipment is replaced or extended. Discrete variables are usually used for the dimensioning of the equipment, whereas continuous variables are generally used for voltages and power flows. In mixed-integer models, all three types of variables can be optimised. Discrete and continuous models on the other hand are restricted to discrete and continuous decision variables, respectively. All reviewed studies are categorised within these three models and listed in Table 5 including their type of solution strategy. The different solution strategies are discussed in [66] with more detail. For reasons of conciseness the various methods have been denoted with indices, which are used in Table 5.

(a) **Mixed-integer models**

The mixed-integer models are the most common ones. They combine binary decision variables (1(Yes), 0(No)) with a set of continuous and discrete variables.

- Mixed-integer linear programming (MILP)[a]

  MILP is a two-step approach. In the first step, an initial solution is determined by solving a linear problem, where all variables are treated as continuous variables, usually using the simplex algorithm. In the second step, successive searches are performed to obtain better solutions for the integer variables.

  For example in [71] MILP is used to determine the achievable gross margin in the different electricity markets for BSS and its resulting operation, as well as for the determination of the storage redispatch and DG curtailment measures and their respective power flows. Whereas, [72] uses MILP to calculate the optimal size and location of feeders and substations over the planning horizon of 10 years.

- Mixed-integer non-linear programming (MINLP)[b]

  MINLP refers to optimisation problems with continuous and discrete variables and a non-linear objective function and/or non-linear constraints.

  In [73] a MINLP is used to decide whether to invest in DG and/or purchase power from the main grid and invest in feeders and substations in case of future load growth. Another approach is used by [74], who formulated the MINLP as a TRIBE particle swarm optimisation and ordinal optimisation with the aim of minimising total costs by optimal allocation of DG. Reactive capabilities of different DG and uncertainty in load demand and generation has been analysed. However, BSS have not been considered. A multi-objective optimisation using MINLP in order to find a trade-off between minimising the investments and the emission of pollutants, taking into account uncertain market prices, has been presented by [75].

- Bender's decomposition (BD)[c]

  In this algorithm the mixed-integer model is separated into two discrete models: the discrete 'relaxed master problem' and a quadratic 'sub-problem'. First, the master problem is solved to decide on investments in new equipment. Secondly, the quadratic sub-problem is solved to optimise the power flow in order to minimise the operational costs.

  A long-term multi-stage model has been presented by [76] and [77]. This model uses new-path and fencing constraints to reduce the complexity of the solution space. This grid expansion planning method minimises investment costs for growing load demand by including DG, similar to [73].

- Genetic algorithm (GA)[d]

  Inspired by natural evolution processes in genetic algorithms generations of individuals exist. Simulating the evolutions of individuals by emulating the process of selection, mutation and recombination of genes, the reproduction is based on fitness functions preferring the best individuals. GA can be used for different purposes in distribution grid planning: In [78] it is used to find the optimal grid topology. In [71]the GA is used for BSS allocation and calculation of grid reinforcement measures. The optimal trade-off between traditional grid expansion and implementation and/or the energy purchase of DG is considered in [79, 80, 81, 82].

- Particle swarm optimisation (PSO)[e]

  PSO is another evolutionary algorithm that simulates individuals (particles) in a swarm and their social behaviour. A vector is used to locate every particle and its velocity in the swarm. The population of particles searches for the optimal solutions using the individual experience of the particles and sharing it with the others. The swarm can also return to promising regions found before. Generally it is used to allocate DG [83, 84, 74] and/or BSS [85], or on-load tap-changer [63]. PSO might also be used to calculate the minimal reactive power output of DGs to solve over-voltage problems [63].

- Expert system (ES)[f]

  Expert systems are knowledge-based systems, that try to emulate the decisions a human would make. Besides heuristic rules a broad data basis like GIS-Data, economic data from asset-management databases as well as the grid topology and measured data are combined for this purpose to create a semi-automatic grid planning process [86].

Qualitative evaluation

Mixed-integer linear models allow a high degree of generalisation. Nevertheless, in order to optimise real grids, non-linear characteristics like cost functions and grid characteristics have to be linearised. Consequently, the optimal solution is not necessarily the best for the real system, due to the simplifications [87, 88].

(b) **Discrete models**

In these models, discrete and binary variables (yes/ no) are used in the objective function formulation to deal with the decision on location and size of the network facilities.

Qualitative evaluation

Discrete models allow the determination of the timing of reinforcement measures for long term planning, but only discrete variables are allowed. Generally, the same restrictions for large scale systems apply as for mixed integer models due to high number of possibilities [66]. To the authors knowledge discrete models are not applied for DG integration in distribution grids, as no work has been published on this topic in the public domain.

(c) **Continuous models**

In continuous models the considered variables have to be continuous and thus the need of discrete decision variables is eliminated.

- Dynamic programming (DP)[g]

  Dynamic programming allows to represent the ever-changing nature of the planning process. This is realised by modelling the states of the network in nodes with certain states. These states can change in time with every investment in grid reinforcement and are based on the former state. In [89] this method is used to realise a long-term planning (10 years) for the optimal sizing, allocation and most important the timing of investment in DG based on measured values (current and voltage).

- Non-linear programming (NLP)[h]

  NLP is a numerical method, which only accepts continuous variables. The most common application for NLP in the context of distribution grid planning is AC optimal power flow (AC-OPF), as used in [71] to minimise active power redispatch for all DG and BSS. NLP is applied by [72] to determine the optimal capacities and production of the DG.

Qualitative evaluation

The biggest advantage of these models are, that no linearisation is required making it a good choice for extension planning purposes of large scale distribution grids. The drawbacks are, besides the large computational effort [60], that these models are badly suited for greenfield considerations [90].

Furthermore, all the methods might be either deterministic or consider uncertainty in the model. The uncertainty can be considered by using a possibilistic[y] approach as used in models that apply a fuzzy total installation and operational cost or a fuzzy non-delivered energy as objective function. A multi-objective optimisation based on fuzzy logic has been presented by [91], who uses a Bellman-Zadeh algorithm to analyse a wide range of technical, economic and environmental criteria to find optimal allocation of DG in distribution grids.
Another approach to handle uncertainty is called probabilistic[z] approach. In this model the uncertainty is calculated by applying a probability distribution function. The power generation or the size of the DG is a common example for a probabilistic application.

[Table 5 about here.]

As presented in Table 5, deterministic approaches without reliability considerations show the highest variety of numerical and evolutionary methods, and are the most commonly used. In studies that implement reliability considerations evolutionary algorithms seem to be the predominant method, because of their advantage to optimise several criteria at the same time.
In most of the cited studies the DSO is at the same time the owner of the DG, BSS or OLTC-transformer and can decide on the allocation and/or the operating strategy of the equipment [73, 74, 77, 76, 78, 75, 91, 89, 85, 83, 84, 82, 79, 80, 81]. Only few works consider that the equipment might be privately owned and operated, as is the case in Germany [72, 86, 63, 71, 92]. In Germany, due to unbundling the DSO is normally not the owner of the DG or BSS and therefore has only very little or no influence on the location. Furthermore, the volatile character of the DG, as well as the stochastic behaviour of loads and the possible participation of DG, BSS and loads at the energy market, lead to extreme scenario parameters. Consequently, the grid is over-dimensioned, if the conventional planning based on worst case scenarios is applied. The over-sizing

problem remains with the presented new grid distribution planning methods as long as extreme scenarios are used, even if the systematic approach of the new methods eliminate the uncertainty of manual planning. The problem can be solved by applying possibilistic or probabilistic methods. Probabilistic algorithms use probability density functions for loads and generation to quantify the likelihood of grid states as for example very rare loading situations and can derive the reliability of the electrical power supply. The main drawback is that high quality time-series of the grid participants are needed to generate the probability density functions, which are often not available in LV grids. This applies especially for the active power flow of BSS as their operation strategy depends on the business case which might depend on the energy market for instance. Furthermore, the reactive power flow of the BSS, depends on other network participants and on the current grid state. Consequently, to generate realistic time-series existing interdependencies in the distribution grid as well as business case related issues have to be considered. These time series can be used as an input for any planning optimisation method mentioned above and should be an improvement to traditional worst case considerations.

Several studies exist combine grid planning with DG and take the active power control of large scale batteries for peak shaving into account [85, 83, 14, 93]. Nevertheless, from the studies mentioned above only [85] and [93] consider reactive power control, even though [94] highly recommends further studies on this issue. This is due to the fact that reactive power control from BSS is as a very easy and cost-effective way of voltage control which is independent from the state of charge of the battery.

4.2. Definitions of behaviours of BSS

As stated before, BSS may provide active and reactive power. The application dependent power flow may either lead to less or to additional grid reinforcement cost [17]. In this section different system behaviours and the criteria of the BSS in order to quantify their impact on the distribution grid planning are defined. In this study the term system refers to electrical systems, whereas the heat and transport sector are excluded. Every BSS may be categorised in one or several of the four categories mentioned hereafter [95, 96]:

(a) Grid compatible

If the minimal technical requirements in regard to quality, reliability and safety imposed by the DSO are fulfilled by the BSS, it can be considered as grid compatible. In the near future operators of DG will need to prove this behaviour via certificates to the DSO. Based on the criteria for to PV systems, possible future criteria which have to be proven by the BSS, are [97]:

(i) Short-circuit current capability, (continuous) current carrying capacity ampacity and switching capacity of the main components

(ii) Active power feed-in

(iii) Active power concept

(iv) Network disturbances like rapid voltage drops, long-term flicker, harmonics and interharmonics

(v) Fault ride through

(vi) Contribution to the short circuit current

(vii) Static provision of reactive power

(viii) Conditions for connecting and protection concept for disconnecting the system

(b) Grid supportive

This characteristics describes the behaviour of the BSS of actively stabilising the grid that goes beyond the minimal prerequisites described before. It has a local component as some issues like over-voltage and over-loading have to be solved locally. Over-voltage may be solved with active or/and reactive power control as addressed for instance by [96]. The market incentive programme from the German Federal Government and the state-owned KfW banking group is coupled to several technical requirements. The most important measure in this context is the limitation of maximum feed-in power of the PV storage system to 60 % of its nominal power at the point of common coupling [98].

(c) System compatible

Analogue to a grid compatible behaviour a system compatibility is given with the fulfilment of the minimal requirements of the BSS to ensure a safe operation of the whole electrical system. In this case the contribution to the spinning reserve, as well as the provision of ancillary services as for instance black start capability and frequency control play an important role. Some of these services, like the provision of primary frequency control, are remunerated whereas some, such as the provision of spinning reserve or active power reduction in case of over-frequency, are not [96].

(d) System supportive

A BSS can be considered system supportive, if it leads to greater flexibility of the electrical system. The operation of the BSS is then optimised to minimise local issues as described for the grid supportive behaviour and at the same time to provide services for the whole electrical system. An example may be the provision of reactive power to reduce local over-voltage issues and the provision of active power to provide frequency control and/or spinning reserve.

5. Overview of large scale battery systems in distribution grids

Large scale battery systems are not clearly defined. They may be defined by their type of operation, as in [99, 100]. In [99] large scale BSS are delemited from small scale BSS, if they supply peak levelling services and are grid connected or if power-quality control applications are applied. A more specific definition of the application of large scale BSS is given by [100], who distinguishes between energy related or power related applications. In energy related applications, the storage is charged and discharged during several hours, reaching one cycle a day. In contrast to this, for power applications the BSS is cycled several times a day and discharged and charged in shorter periods (typically seconds and minutes). The type of application directly affects the range in which the rated power range of the BSS tends to be and might be used as an indication, as listed in Table 6 according to[101].

[Table 6 about here.]

In subsection 5.1 the market potential of large scale BSS in German distribution grids according to the definition mentioned above is estimated. The operation strategies of the two most promising business cases are analysed in subsection 5.2 and 5.3 and the impact of the operation strategies is concluded in subsection 5.4.

5.1. BSS applications and German energy market

In broad terms, there are two ways to gain monetary benefits along the electricity value chain with existing BSS applications in the German electricity market: first, revenues received by the storage owner or operator and second, cost reduction or avoidance by the storage owner or operator [102]. Generally, revenues can be achieved through existing markets and bilateral contracts. Cost reduction or avoidance on the other hand is highly based on individual use cases. Some important application analyses have been summarised for the German electricity market in [103, 104, 105, 106] and are shortly presented in the next sections together with their potential benefit estimations:

(a) Market revenues

(i) Power exchange markets:

As electricity is a homogeneous commodity and the majority of the power supply must be consumed at time of production, electricity prices show a high volatility. In addition, the short-term demand is not very price elastic [107]. These circumstances allow inter- temporal arbitrage transactions at the EPEX-Spot (day-ahead and intraday market). Arbitrage contains purchases of electricity in times of low energy prices (off-peak prices) and sales of electricity when prices are comparatively high (peak prices) [108]. The attractiveness of the application depends on price spreads and the frequency of price spreads in these markets. On the day-ahead market, 24 hour single contracts and diverse block contracts are traded for the next day via a daily static auction. The intraday market starts shortly after the day-ahead market (trades for the following day start at 3 pm and end 30 minutes before the actual physical delivery of the respective contract) and is organised by continuous trading.

(ii) Control reserve markets:

A stable operation of the power supply system at a system frequency of 50 Hz requires that the system balance of feed-in, off-take and losses are balanced at any time or that it will be balanced in case of any deviations in a short period of time [109]. An increase or decrease in net output of BSS can ensure a real-time system balance [110]. Since 2001, the German TSOs procure their needs for different control reserves (primary, secondary and tertiary control reserve) on an open, transparent and non-discriminatory market. The main differences between the three control reserve forms are the tender time and period, the product time-slice, the award criteria and the remuneration. In addition, positive and negative SCR and TCR are separately marketed, whereas in the case of PCR the power increase and decrease must be ensured by a single offer, but the forms of control reserve can be provided by various technical units (also known as pooling).

(b) Revenues based on bilateral contracts

(i) Voltage support:

In order to maintain stable network operation, the voltage level must be kept in certain ranges. The static voltage support can, among others be achieved by a local offset of reactive power [111]. BSS with an inverter and a corresponding power electronic can principally provide reactive power [112]. A compensation of reactive power is exclusively paid on the high and extra high voltage level by the respective TSO. On the distribution level the requirements are part of the FNN-guidelines but there is no monetary compensation [95].

(ii) System restoration:

BSS can be used to energise transmission and distribution lines and have the ability to synchronise sub-systems as well as back-up other black start units [105]. In Germany, each of the four TSOs in cooperation with the DSOs are obliged to have a sufficient capacity of black start units plus a concept for the restoration of supply in their control area. The black start capability is not explicitly defined in the Transmission Code. The requirements for the type, scope and remuneration are negotiated bilaterally.

(iii) Redispatch:

In many areas in Germany, transmission capacities are not keeping pace with the changing feed-in and off-take infrastructure. In order to ensure security of supply, TSOs with the help of DSOs take redispatch measures, adjusting feed-in from particular generating and storage facilities [113]. A transparent market for redispatch does not exist. The selection of generators for redispatching is based on their location in the network, their generation form and their size, which determines either the cost-based (where the adequacy of costs is regulated) or market-based (based on individual bids submitted by the generators) redispatch [114].

(c) Cost reduction or avoidance

(i) Uninterrupted power supply (UPS):

Large and long power cuts ($>3\,\text{min}$) arise relatively arbitrarily in Germany. However, voltage dips ($<1\,\text{min}$) as well as short interruptions ($<3\,\text{min}$) occur 10 to 100 times per year [114]. Therefore, depending on the specific outage times and individual power quality needs (e.g. voltage, frequency, harmonics), a UPS system can consist of a BSS in combination with a generation unit like a diesel or gas generator or of a battery only [106].

(ii) Balancing group management (BGM):

With the liberalisation of electricity markets in Europe and Germany, the balancing group system was established. Accordingly, each producer or consumer must belong to a balance group and all balance groups must be levelled at a quarter-hourly basis. The German TSOs are liable for determining and settling the amounts of balancing energy in their control area, using a common symmetric imbalance price for each 15-minute time period (German: regelzonenübergreifender einheitlicher Bilanzausgleichsenergiepreis, reBAP) [115]. Consequently, a BSS can optimise the individual energy balancing costs.

(iii) Energy cost management (ECM):

The benefit area is similar to arbitrage at power exchange markets. In this case not wholesale prices but individual end-user tariffs are relevant. The BSS can avoid high price energy purchases during peak demand hours for residential and commercial/industrial users [116]. Since 2010, according to section 40(5) EnWG energy suppliers are obliged to offer load-variable and daytime dependent tariffs. The tariff-structure and -spreads depend mainly on the respective supplier and individual electrical demand amounts (e.g. industrial, residential).

(iv) Reactive power management (RPM):

Producers and network operators need to transfer the apparent power according to the active and reactive power demand of the end user. Common supply contracts in the industry allow that 50 % of the active energy can be obtained free of charge as reactive energy, which corresponds to a $cos\varphi$ of 0.89 [117]. In case of a higher demand for reactive power an additional fee must be paid, which is subject to individual negotiations. This inductive reactive power demand can be covered amongst others by a BSS.

(v) Demand management:

As standard load profiles are applied in the customer segment and only annual energy consumptions are measured, no tariffs with power limits or incentives are available at the moment. This can potentially change with the roll out of smart meters. However, industrial consumers typically have two price components: expenses of the peak power demand and expenses for the consumed energy [103]. Usually, demand management is done by the retraction of running processes. Therefore, a load-shift via BSS may have (alongside with economic aspects) production-related benefits.

(vi) Renewable energy self-consumption (RESC):

End-consumers with generation capacity (e.g. photovoltaics) can increase the amount of self-consumed energy by adding BSS. With the increasing difference between cost of generation and purchase price BSS become more and more attractive to end-consumers. For instance, PV-generation costs and feed-in tariffs have dropped well below purchase prices from the grid, whereas purchase prices have increased continuously [103]. It is noteworthy that due to the EEG amendment from 2014, newly installed systems over 10 kW or 10.000 kWh/a are surcharged for own consumption. Overall, the attractiveness of RE self-supply depend highly on electricity fee regulations.

(vi) Grid expansion relief:

Due to the growing energy demand, decoupled supply and demand regions, as well the fluctuating nature of most renewable energy generation, further investment in new lines, transformers and substations may become necessary [118]. According to the usual load characteristics, the available transmission capacity limits only the maximum transmittable power, but not the energy [119]. BSS can help defer or avoid grid expansions by storing energy. Nevertheless, BSS in general are more cost intensive and the current incentive regulation (ARgeV) does not consider alternative and perhaps more expansive infrastructure investments.

According to a German market analysis based on data from 2013 the benefits can be grouped in accordance to their market potential (see Table 7). The market potential consists of three core aspects: conceivable revenue, applicability for BSS and a favourable legal framework. Only a low potential for BSS benefits lies in grid expansion relief, voltage support and system restoration; redispatch, demand management and reactive power management hold a medium benefit potential. A high market potential is given by energy trading at the day-ahead and intra-day market, frequency support, un-interruptible power supply, balancing group management, energy cost management and renewable energy self consumption. The highest revenue potential for the market based applications lies in the primary control reserve market whereas the highest cost reduction potential can be seen in maximising the self consumption using renewable energies, especially for households. Therefore, many BSS projects, especially in Germany, but also world-wide focus on these two applications [120]. An up-to-date world-wide database on energy storage systems and their applications is maintained by the US Department of Energy [121], which confirms that these two applications are the most common. Ergo, the focus of this work lies on operating strategies for the maximisation of self consumption (subsection 5.2) and primary frequency control (subsection 5.3). Another approach is to combine complementary business models, this may increase the profit compared to a single revenue stream [122].

[Table 7 about here.]

5.2. Detailed overview of operating strategies for self-consumption

With the rise of DG the idea of the prosumer (entities that consume and produce), first mentioned in 1980 [123], became more popular. The main motivation to become an electrical prosumer as defined in [124], is that self-consumption of locally generated electricity, as defined in [125], is more profitable than drawing it from alternative supplies. This is the case if the levelised costs of electricity (LCOE) of the DG can compete with the cost to draw electricity from the power grid (electricity retail price). A comprehensive manual to calculate the LCOE for renewable energies was first presented by [126] and has further been discussed by [127] [128] and [129]. To incorporate the cost of storage [130] proposed to calculate the levelised cost of stored energy.

A comprehensive overview on grid parity world-wide is given by [131]. It is shown that Europe was the first main market world-wide where grid parity was achieved in 2010. It is quite likely that the market volumes for self-consumption business cases will grow in the future as the trend of falling LCOE of DG and BSS continues. The LCOE of PV, for example, are assumed to decrease by 30-50 % from 2014 to 2030 [132]. An even more drastic price decline is foretold for BSS, especially for lithium-ion batteries (LIB). The lowest battery cell price for utility scale LIB could decrease by 64 % from 2014 to 2020 [133]. Although normally only addressed as LIB, there are at least four promising types of LIB suitable energy storage applications with different cell chemistries [134] and price reduction potentials till 2020 [133]: lithium manganite (39 %), lithium nickel cobalt aluminum oxide (50 %), lithium-iron phosphate (37 %) and lithium titanate (25 %). A more conservative meta-study conducted by Nykvist et al. indicates that the costs of LIB for battery electric vehicles could fall below 150 USD/kWh by 2025, and therefore decrease by more than 50 % [135]. The lowest battery cell price for utility scale flow batteries is predicted to decrease by 48 % until 2020, making them the second most interesting battery type concerning the price reduction potential [133].

The liberalisation of the energy market since the 1990s has not lead, as theoretically predicted, to a decline of the electricity price for household consumers due to more competition, but to an increase in all 27 member countries of the EU-27, except Finland, between 1998 and 2008 [136]. As electricity prices are much harder to predict than, for example, the LCOE of PV a large variety of methods have been applied over the past 15 years [137], indicating that the electricity price for households will further rise all over Europe [136]. Keeping in mind the big uncertainty of predicting these prices the electricity retail price in Germany is likely to increase until 2030 according to a technical report commissioned by the Federal Ministry for Economic Affairs and Energy [138].

In countries with lower LCOE of PV compare to Germany like Spain for instance, self-consumption systems might have a positive NPV, but a possible back-toll fee could turns a profitable system to a negative NPV[139]. Therefore a favourable legislative framework, as it is the case in Germany, is mandatory for this business case. By analysing the Italian market, one can deduce which size is more profitable in a post feed-in market. It can be concluded that small residential PV systems have higher net present values than bigger systems, as the economy of scale does not compensate the benefits of smaller systems [140]. Therefore, the trend of installing PV systems in LV grids in Germany is likely to continue. PV systems in southern Germany reached PV grid parity in 2012 [2]. With only a PV-system to match the demand, the achievable self-consumption rates are limited, and can only be increased by demand side management (DSM) and BSS come into play. It is shown by [141] that BSS have a higher potential to increase self-consumption than DSM [141]. Consequently, self-consumption increase is mainly realised with residential energy storages (RES), as this business case became profitable in 2013 in Germany [142]. As described before, the benefit in 2013 results from the PV LCOE, which are currently between 9.8 and 14.2 EURct./kWh in Germany [143], and the electricity costs for households, which amount to 28.9 ct./kWh [144]. It is noteworthy that due to the EEG amendment from 2014 newly installed systems over 10 kW or 10.000 kWh/a are surcharged for own consumption (currently with 6.2 EURct./kWh). Therefore, the theoretically achievable profit margin lies between 8.5 and 19.1 EURct./kWh. This led to an installation of more than 4600 residential storage systems for self consumption in Germany until June 2015[145].

In the industry segment the PV generation costs are generally 2 EURct./kWh lower than in household applications because of the larger systems sizes and lie between 7.8 and 14.2 EURct./kWh [143]. The power purchase costs for large customers with a consumption of 100 GWh/a range between 4.1 and 15.6 EURct./kWh. Thus, the theoretical realisable value range (considering the EEG surcharge) is 0 to 5 ct./kWh.

But could it be economically feasible to pool the prosumer and instead of having a BSS and PV-system in every household share and scale them up? [146] showed that the pooling of prosumer generators and loads has been beneficial in all calculated scenarios in the UK compared to a single prosumer. This is due to the combination of PV systems, wind turbines and loads. By doing this the self-consumption level could be raised up to 17,5 % , wherefore the economics in case of grid parity improve significantly. However, BSS were not considered in this study. Large scale or pooled BSS that apply a self-consumption maximisation can be addressed as community electricity storage (CES), as defined in [147, 148]. A more detailed definition of CES is given in [149]. Parra et al. [150] conducted a study in which the LCOE of single households in the UK using PV residential storage systems and using a CES instead were compared. It has been shown, that the LCOE could be lowered by 37 % for a 10-household community and 66 % for a 60-household community. In Germany, CES, diverging from the definition in [148] cannot be operated or owned by the DSO using the CES to participate in the energy market because of the unbundling. The CES has to be owned and operated by a citizen cooperative or an external storage operator, for example. In Germany, no similar calculations considering the potential of lowering the LCOE have been conducted, but [151] showed that by applying CES the losses caused by the grid-compatible storage operation can be lowered by 50 % on average compared to RES. With the existing legal framework the business models of residential storages and CES cannot be directly compared because of the additional burden of extra fees and taxes for CES. Nevertheless, the studies mentioned before seem to indicate that CES have some advantages over residential storages.

The operation strategies however, can be transferred and classified into the following four categories [95, 98]: direct loading, schedule mode, peak shaving and based on a prognosis. A more detailed description and quantitative comparison of the control strategies for residential systems can be found in [20]. Although being very similar, the control strategies for CES are different, as the incentive programme introduced by the German government only supports storage systems for grid connected PV systems up to 30 kW [98]. As a consequence, CES do not have to limit the rated power of the DG P_{rDG}. For the following graphs it is assumed that the CES is connected to the low voltage and the yearly energy consumption is equal to the energy production of the DG in the LV grid. It is assumed that all DG are PV systems. As suggested in [152] the ratio between capacity and the rated power of the PV system is 1:1. The implementation of the different operating strategies of the German CES projects listed in Table 8 are sorted in the four categories and described briefly.

(a) Direct loading

The generated energy is directly stored in the BSS if the residual power P_{res} of load and generation is positive. This simple strategy maximises the self consumption rate as it ensures that the BSS is loaded as soon as possible. Drawback of this strategy are the steep gradients depicted in Fig. 7 and that, depending on the battery capacity, an excessive feed-in to the grid might occur during peak irradiation around noon, if there is no PV power limitation on the power of the PV systems.

[Fig. 7 about here.]

A grid compatible operating strategy using direct loading to ensure a maximal renewable energy self-consumption rate (RESCR) is used by [153] and [154]. In [153] the BSS is placed in the LV side of a micro grid with DG, which is connected to the public grid via one MV/ LV transformer. The charging and discharging of the battery is calculated in 1-h steps, from measured and synthesised time series. The main differences in the CES project of [154] are that the generation and load of every participating prosumer is measured every 5-7 seconds and that the BSS is not necessarily placed at the same location as the DG and consumers. The idea of this project is that every participant may use a part of the battery that is virtually partitioned to increase the individual RESCR.

(b) Schedule

In this strategy, the time to charge the battery will be shifted to a typical time with high radiation. The schedule mode with constant charging power is depicted in Fig. 8 showing a more favourable behaviour from grid perspective because feed-in peaks as in the direct loading strategy are prevented.

[Fig. 8 about here.]

Nevertheless, the self-consumption rate might be reduced, as in days with lower radiation the BSS might not be fully loaded. Several strategies have been proposed for this purpose. The main differences are that [155] and [156] propose a starting point around noon and charge the battery with full power whereas others, for example [157], suggest a constant charging power over a larger period. Currently there is no CES project in Germany known to the authors using this strategy.

(c) Peak-shaving (load levelling)

The main objective of the peak shaving strategy (Fig. 9) is to avoid over-voltage and equipment overloading issues by limiting the power at the PCC and using the remaining residual power to charge the battery [158, 152, 159].

[Fig. 9 about here.]

The limitation of power at the PCC should be based on the voltage at the PCC, the power range of the battery, and the PV penetration of the grid [158]. The main objective of this strategy is to not surpass a certain level of P_{res}/P_{rDG} at the PCC of the BSS. There are mainly three possibilities to achieve this aim:

(i) The battery is sized for the worst case, e.g. the day with the highest irradiation and no load, as in [160].

(ii) The power of the DG is curtailed in case of a full battery, as depicted in Fig. 9 and described in [159].

(iii) Instead of curtailing the DG an additional load is used to reduce the residual load by using, for example, power-to-head [161].

This grid supportive operating strategy is applied to large scale BSS by [14], [160], [162] and [163]. The focus of IRENE Project lies on grid expansion relief. Therefore, one or several BSS are dimensioned and placed strategically in the LV to mitigate the total feeder RPF to 70 % of the cumulated P_{rDG} of the respective feeder in which the BSS are installed. Additionally to this active power control, a reactive power control is implemented. The calculation of the set-points of P and Q are calculated externally and not by the BSS itself. [160]

Similar to the aforementioned project the BSS in Fechheim limits the power to 40 % of the cumulated P_{rDG} of feeder in which the BSS is allocated with an active power control and uses a reactive power control to reduce the voltage in the case of a fully loaded storage [162].

The aim of the SmartOperator project is to minimise voltage deviations and line utilisation. The BSS is dimensioned to enable a peak shaving of 50 % for a period of 5 h [163] based on initial studies by

[164]. A learning algorithm is used to calculate the forecast of generation and load as well as future grid states, based on real time data of voltage and current [165]. This forecast is used to calculate the active and reactive power flows of the BSS to ensure peak shaving of the PV systems and that the voltage values of the grid nodes stay within given thresholds.

The advantage of peak shaving is that critical voltages might be avoided by limiting the feed-in power. The voltage can be further reduced by absorbing reactive power. From the point of view of self consumption maximisation, a problem is raised during cloudy or foggy days, when there is not enough radiation to charge the battery. Consequently, the self-consumption rate will be reduced. On the other hand, during high irradiance days, the power curtailment is high as can be seen in Fig. 9 for case (ii). For case (i) and (iii), however the additional investment costs have to be considered critically. This applies in particular for case (i) in a distribution grid with many wind generators as in this case the energy to power ratio of the BSS needs to be higher as for PV systems [164]. To avoid these losses or additional invest, an optimisation of the power flow based on a prognosis is proposed in the next strategy.

(d) Prognosis based strategy

This strategy uses load and weather forecast data to adjust the charging power and feed-in power to get a fully charged battery at the end of the day and/or avoid over-voltage and asset over-loading (Fig. 10).

[Fig. 10 about here.]

A control loop within the day corrects the deviation from the forecast data. This strategy reaches the highest self consumption rate after the direct loading strategy while still being grid supportive, this is due to the lower curtailment losses compared to other strategies [20, 125]. The main differences of this strategy are the forecast techniques. Principally, the previously published studies can be divided into four classes:

(i) Studies using a perfect forecast [152, 166].

(ii) Studies using synthetic forecasts (modified measured time series) [167, 168, 169].

(iii) Studies based on external weather-based forecast from meteorological services [170, 171, 161, 172]

(iv) Studies that base their forecast on a persistence method based on values measured by the PV-system [167, 125, 173]

Obviously, no prediction errors apply to a perfect forecast. The only difference is the time resolution, which in the case of [152] is 1 min and in the case of [166] is 15 min.

One proposition for modelling synthetic forecast which has been presented by [168] and also used by

[169], uses the Spherical Harmonic Discrete Ordinate Method [174]. In this model measured data is used to generate the global solar irradiation at ground level for the next days. By forecasting the weather data a minute-based PV power is calculated taking into account the orientation and angle of the power plant. An error analysis of the model has shown that the average error (rRMSE) of the weather forecast for the next day is 32.5 % for one site. This is very close to the accuracy of approximately 30 % of current numerical weather prediction models for Central Europe [175]. The value increases for a longer forecast horizon. Instead of a physical model, [167] uses a noise sequence to fabricate a forecast based upon the hourly average of the measured data. This results in an hourly forecast for the next day with an rRMSE of 30 %.

Several studies use external weather forecasts and calculate the AC power profile of the PV system according to predicted irradiance instead of synthesising the forecast data. A simple forecast method in which the historical data of the solar irradiance and the predicted weather conditions (sunny, cloudy, rainy) are used to calculate the PV profile in 1 h steps is presented by [170]. Also on an hourly basis, [171] predicts the PV power output for different region sizes in Germany based on forecasts for up to three days ahead that are provided by the European Centre for Medium-Range Weather Forecasts (ECMWF). For a single site and day ahead forecast an rRMSE of 36 % could be quantified. As the rRMSE decreases as the examined area rises for the whole of Germany the accuracy of the rRMSE is 13 %. Another study uses the irradiance forecast based on the Weather Research and Forecasting (WRF) Model [176] and evaluated the deviation of the measured irradiance values of a pyranometer (5-8 %) and the PV power output (3-5 %) on a 15 minute base for a PV plant in Italy [172]. Historical forecast data of irradiance and temperature in 1-h steps from Meteotest [177] has been used by [161] to calculate the PV output power and it is shown that the RESCR decreases by 15 % if forecast errors are taken into account instead of assuming a perfect forecast .

Another approach is to use persistence weather forecast. The forecasting method is based on extrapolating the current or recent PV power plant output taking into account the changing of the sun angle. Since the persistence is based on stochastic learning technique from historical pattern, the accuracy highly depends on the forecast horizon due to the change of cloudiness [178]. The forecast method is suitable for minute based forecasts for one location. For simulation purposes, an autonomy forecasting using a learning algorithm is more preferable compared to the one that depends on the global weather data. The differences of the different persistence forecasts arise in the algorithms used to predict the load and PV output and the values that are used to correct the intra-day deviation from the forecasted values. As described before, [167] uses a synthesised forecast data with a noise and a learning algorithm based on historical data to adapt the charging algorithm to the PV output and load within the day. Also [169] uses a synthesised PV forecast; concerning the load an easier method is proposed by predicting it based on the load profile of the past five days. In this method, the day is divided into three periods:

midnight to sunrise, sunrise to sunset and sunset to midnight. Using the arithmetic means of the past five days, the load profiles of each period define the load for the next two days.

Fully autonomous persistence, which is not dependent on an external or synthesised forecast is presented by [125] and [173]. In [125] a method is used that assumes a load profile for the predicted weekday identical to the load profile of the weekday from the previous week and predicts the PV for the next day based on the day before. To correct prediction errors within the day a proportional plus integral controller (PI-controller) adjusts the feed-in limit by constantly comparing the difference between target and actual SOC. The load prediction in [173] is the same as before-mentioned. The study also shows that the forecast of the PV output has a stronger impact on the curtailment losses and self-sufficiency rate than the load forecast compared to a perfect load forecast. Therefore, an elaborated method for the PV persistence forecast is presented: First a bell-shaped profile based on the last ten days is calculated. To achieve a higher accuracy a moving horizon is introduced that combines the PV data from the last 4.5 hours with the bell-shaped profile. For the intra-day correction the feed-in limit is adapted dynamically every 15 minutes by running an optimisation with 15 minutes of forecast resolution and 15 hours of optimisation horizon, if the measured values (residual load and battery charge power) differ from the predicted. This differs from [125] and [169]where the optimisation for the day is conducted only once and the correction due to forecast errors is done by comparing the forecasted SOC with the measured SOC. Thus, inaccuracies may occur as the SOC cannot be measured directly, but is a calculated value from the battery management system.

The differences of the forecast and operation strategy lead to similar curtailment losses as in [125], but the self-sufficiency is higher with the adaptive forecast approach of [173]. It could be shown, that the adaptive forecast shows advantages over a persistence forecast with a fixed horizon. As the control algorithm based on autonomous persistence forecasts reaches similar curtailment losses as the one based on external forecasts [173], these forecasts seem to be preferable as they need no additional hardware and are independent of the additional cost of external forecasts or meteorological services. Nowadays, up to one third of the installed residential PV storage systems in Germany are capable of applying a prognosis based charging algorithm [95, 145].

A prognosis based operating strategy is applied to large scale BSS by [93], [71], [151], [169] and [179]. In the project SmartRegion Pellworm different business models have been tested and affect the operating strategy. The scenario which maximises the RESCR is called "Sustainable Regional Load Supply". The active power flow of the BSS is an output of an optimisation to maximise the profit for the different business models [93] and is combined with an OPF simulation to incorporate grid restrictions to calculate the reactive power flow [71]. The prognosis is carried out using a perfect foresight based on measured time-series for load and generation and historic market data. This central approach ensures a grid supportive behaviour of the BSS.

The EEbat project combines the aim to relieve the grid and maximise self-consumption. The grid relief is achieved, by applying the peak shaving strategy using active power control and curtailing the RPF to 50 % of the cumulated PV installed in the LV grid. A persistence forecast for load and generation is used to adjust the charging power and ensure a maximum self-consumption [169]. Furthermore, the differences between using standard load profiles (SLP) [180] and realistic load profiles as inputs for the operation strategy are quantified. For this calculation the RESCR and the financial benefit of a CES allocated in a LV grid consisting of 50 households with PV generation and loads are compared. It is shown, that SLP are sufficiently accurate to be used as input for this operation strategy. Reactive power control is not considered in this study.

Another charging strategy is implemented in the Smart Grid Solar project. To predict the PV generation, a short term weather prediction based on sky-images instead of measured electrical values is implemented. The charging algorithm is rather simple as the battery is charged with a constant charging power in case the residual power exceeds a given limit. Another control strategy developed in the same project is based on the measured voltage at the PCC which is kept within a given range by charging or discharging the battery [179].

The impact of different operating strategies on distribution grid planning is discussed in section 5.4.

[Table 8 about here.]

5.3. Detailed overview of operating strategies for primary frequency control

Due to the fact that there is only very limited possibility of storing electric energy in the electrical system nowadays, a constant equilibrium between active power generation and consumption must be maintained. An indicator for the deviation in this balance is the system frequency, since it is a measure for the rotation speed of the synchronised generators. An increment of the total load will decrease the speed of the generators and hence lower the system frequency. A decrease of the demand on the other hand leads to an increase of the system frequency. [181]

Since frequency deviations can not only damage electronic devices connected to the grid but also endanger the stability of the whole electrical network, the German transmission system operators (TSOs) are legally obliged to maintain the system frequency within the strict limits of 50 Hz ±1 % (see also section 2) [23, 26]. In order to achieve this goal, a certain level of active power reserve is required to re-establish the equilibrium between demand and generation in case of unbalances (this can be unbalances between instantaneous power consumption and generation, but also major power disturbances in the grid) [181].

The “Operational Handbook” of the ENTSOE (European Network of Transmission System Operators for Electricity), which sets general rules and technical recommendations regarding reserve power levels and their associated control performance, defines three different reserve levels: primary, secondary and tertiary control reserve [182, 183]. According to the Grid Code of the German TSOs these reserve levels are also valid in Germany [182]. The primary control reserve (PCR) is automatically activated within a few seconds after detecting a frequency deviation according to the curve depicted in (Fig. 11).

[Fig. 11 about here.]

The main goals of the secondary control reserve (SCR) are to restore the rated frequency of the system, to release primary reserves and to restore active power interchanges between control areas to their set points. The tertiary control reserve (TCR) aims to replace the secondary reserve, manage eventual congestions and bring back the frequency to its rated value if secondary reserves are not sufficient. [27]

In Fig. 12 the interaction as well as the starting and deployment times for the three reserve levels according to the guidelines of the German Grid Code is shown [27].

[Fig. 12 about here.]

In Germany, large scale battery storage systems are almost exclusively used to provide PCR. There are several technical as well as economical reasons for this. From a technical point of view batteries perfectly suit the operational requirements for providing PCR since they are able to deliver the requested power very accurately within a time frame of less than one second with a very high reliability [184, 185]. Although large scale batteries usually have a very limited storage capacity compared to other storage technologies such as pump storage systems [111], this storage capacity is fully sufficient (when made sure that the state of charge (SOC) of the battery is kept at an optimal level during operation (see below)) to bypass the time until primary control reserve is relieved by secondary control reserve (see Fig. 12) [186]. The need for a relatively low storage capacity of course also has the benefit of reducing investment costs and hence has a positive effect on the profitability of the battery system.

From a financial point of view, however, there are further points that make the provision of PCR the most attractive business case for large scale batteries nowadays [40]. As shown in section 5.1, the main reason for this is, that under the actual economical and legal framework, the weekly income is the highest when compared to other business cases. Because of this, it is foreseen that already existing PCR battery projects will turn out as being profitable in the near future [40, 186]. Another argument making the provision of PCR with large scale BSS very attractive from an investor's point of view is the already existing PCR market with its clear rules. This on the one hand reduces the risk for future income expectancies and on the other hand lowers marketing expenses.

The mentioned technical as well as economic reasons for providing PCR with large scale batteries have led to an increment of existing as well as planned primary frequency control battery projects in Germany over the last years. A chronological overview of recent large scale BSS projects for primary frequency control in Germany are listed in Table 10. The first battery providing PCR within the European grid was a NAS battery. This battery was integrated into the German network in the year 2012 by the Younicos AG. As can be noticed, since then the installed power of the battery systems has been steadily increasing. Furthermore, it can be derived from Table 10 that almost all projects apply Li-Ion technology. One of the main reasons for this are the rapidly falling costs for Li-Ion batteries over the last years [186, 187]. Besides this, Li-Ion batteries have also one of the highest roundtrip efficiencies in comparison to other battery technologies, a very high energy density, high lifetime expectancy as well as a very favourable power to energy ratio for providing PCR [188, 189]. This means that a high installed power does not lead to an unnecessarily high storage capacity. Nonetheless, flow batteries in primary reserve applications have also been discussed in literature [190]. The same author claims that short response times as well as the ability of some systems of being overloaded give BSS an advantage over conventional facilities. As more and more private companies plan PFC projects without federal funding one can deduce that this business case seems promising from their point of view and is technically mature. Still, the pre-qualification that allows the facility to operate at the PFC market is the bottle neck at the moment, as most of the commissioned projects did not pass the pre-qualification yet. Another trend is the increase of the system size of large scale BSS as it can be seen for the most recent systems under construction in 2016.

Whether the number of grid connected large scale battery systems will continue to rise in the future depends to a great extent on prices decline for batteries and the future development of the remuneration for primary control reserve. Since the request for batteries has steadily been increasing over the past years, battery costs are generally expected to fall in the future [185, 191, 192, 133]. For a more detailed cost prognosis please refer to section 5.2) The future development of the remuneration for PCR, however, is relatively unclear since it depends on many factors that are barely predictable. These are for example the number of players in the PCR market and the future request for primary reserves. In [193] and [194] it is estimated that the future request for primary reserves will rise due to an expected increase of the share of fluctuating renewable energy sources along with their low predictability of electricity production. In [40] and [195] on the other hand it is estimated that the request for primary reserves will stay more or less constant in the future. This is explained by the fact that the demand for PCR in Europe is actually determined on the basis of the simultaneous loss of the two largest power plants within the European grid, which is not expected to change significantly in the future. A comprehensive study on how the rise of variable renewable energies and the reserve market interacted in Germany in the past years is given by [115]. Hirth and Ziegenhagen [115] try to explain the possible reasons of the reduction of the balancing reserves and costs and the simultaneous increase of installed wind and solar power. One of the major findings is that the wind and solar power forecast errors might not be the most prominent driver for the balancing reserve requirement, but that other factors like the design of the control market might be more important. Due to all these uncertainties, the prediction of the price development for PCR is hardly possible and expert opinions strongly differ in this point [185, 195, 115].

Another important factor that can have a big influence on the development of the number of large scale batteries in the German grid are future adjustments of the participation conditions for the PCR market. On their basis it is not only decided who is able to enter the market and who is not, but they also set the operational framework for PCR providers. On the other hand, this can have a big influence on the economics of PCR projects. For example, if the required storage capacity of PCR batteries has to be increased, as it is currently discussed [185, 196], it would have a negative impact on the economics of those projects.

The guidelines for entering the PCR market are defined by the TSOs, since they are legally obliged to ensure that all technical standards for operating the electrical network are safely fulfilled [23]. The actual key parameters for the provision of PCR are summarised in Table 9. Furthermore, according to the German Grid Code all prospective providers of PCR have to complete a pre-qualification procedure to demonstrate their ability to meet the requirements in this respect [27].

[Table 9 about here.]

As can be seen in Table 9, the primary control reserve has to be provided for a tendering period of one week with an availability of one hundred percent. For battery storages this would mean that they would have to be dimensioned for the case that the full offered power is requested continuously during a whole week. The dimensioning for this unrealistic worst case scenario, however, would make all battery projects uneconomical. Because of this, the German TSOs have defined "degrees of freedom", which give battery operators the chance to readjust the SOC of the storage system during operation [197]. As a consequence, the required storage capacity is reduced, since the SOC can be kept at a level, where it is ensured that the battery is able to provide the requested balancing power until primary control reserve is relieved by the secondary control reserve Fig. 12. For this case a power to energy ratio of one (e.g. 1 MWh / MW) is fully sufficient [186, 187].

According to [184] and [187] the optimal SOC for batteries providing primary control reserve lies around fifty percent. The reason for this is that the network frequency generally fluctuates more or less normally distributed around the nominal value of 50 Hz [103]. Therefore, approximately the same amount of balancing power has to be provided in positive (unload) as well as negative (load) direction. Due to the losses of the storage system, however, the SOC tends to fall in the long run. Hence, it is advisable to keep the SOC slightly above fifty percent [184]. The TSOs in total defined six degrees of freedom for SOC adjustments. They can be found in [197]. The main difference between them is that some generate extra costs for the battery operator and some do not. Those degrees of freedom that do not generate costs can be applied as often as required. Those that do generate costs on the other hand should be applied as seldom as possible. In this case the decision whether to use the degree of freedom or not becomes more complex and should be determined on the basis of a cost benefit calculation. All six degrees of freedom listed in [197] are briefly described hereafter (italic letters): As can be seen in Fig. 13 the *"optional overfulfillment"* gives the battery operator the chance to provide 20 percent more balancing power than required, if it is useful for an adjustment of the SOC.

[Fig. 13 about here.]

The degree of freedom *"dead-band"* makes it possible to readjust the battery SOC by using the dead-band (Fig. 14). One condition for the application of this degree of freedom is that the behaviour of the battery must always support the stability of the electrical network, meaning that, for example the battery is not allowed to charge when positive primary control reserve (unload) is required.

[Fig. 14 about here.]

One degree of freedom that has to be remunerated when applied is the option to charge or discharge the battery with *"schedule transactions"*. In this case the SOC can be optimised by purchasing or selling energy at the energy market (stock market or over the counter transactions). Of course, when using this degree of freedom the battery operator has to make sure that the sum of battery output and purchased / sold energy corresponds exactly to the requested value by the TSO at any point in time. An exemplary behaviour of the battery during a schedule transaction is shown in Fig. 15 and Fig. 16. In this case the SOC of the battery is in its lower half at 8:00 o'clock. Since the battery has to keep continuously unloading due to low grid frequencies, a schedule transaction is carried out between 9:00 and 9:15 o'clock. As can be noticed, this prevents the SOC from reaching a critical value, since the battery is loaded instead of unloaded in this time window (see Fig. 16).

[Fig. 15 about here.]

[Fig. 16 about here.]

Similarly to the just described degree of freedom it is possible to *"load or unload the battery with another technical unit"*. One condition for doing this is that all entities involved in the re- or discharging process must belong to the same balancing group. Furthermore, an optimal interaction of the involved units has to be demonstrated in advance.

Another degree of freedom for batteries consists in the *"relocation of the dead-band when grid-time corrections are planned"*. When required the PCR provider is informed one day in advanced about the target frequency for the upcoming day by the TSO. In this way the PCR provider is able to prepare the dead-band shifting for the time period of the grid-time correction.

[Fig. 17 about here.]

According to [181], the maximum deployment time for PCR increases linearly with the requested primary control power. Starting from a value of zero the maximum offered power by a PCR provider must be fully activated after 30 seconds at the latest. However, BSS that are able to provide the requested power much faster are allowed to use this characteristic as a degree of freedom. This means that battery operators are allowed to use the whole *"permissible operating range"* depicted in Fig. 17 to readjust the SOC of their storages.

[Table 10 about here.]

5.4. Impact of BSS maximising self-consumption and applying PCR on distribution grid planning

In this section the impact of the operating strategies derived from the business cases of self-consumption maximisation and primary control reserve as shown in subsection 5.2 and 5.3 on distribution grid planning are discussed. How BSS can be implemented in traditional grid planning as presented in subsection 2.2 is subject to ongoing research. However, [198] gives some hints by showing that DSO only consider active power flows, which seems a viable proposition as they are responsible for the revenue stream for the two business cases and a reactive power control is not yet mandatory for large scale BSS. Therefore, in the fist part of this section only the active power flows are evaluated using the worst case approach of traditional grid planning and the resulting diversity factors for BSS are listed in Table 11. Secondly, the effect of reactive power control on the planning is discussed briefly as it can be considered independent of the business case, given that the power electronics is able to provide a four quadrants operation. In the last part deficiencies of the traditional planning methodology are presented and possible steps to new planning approaches, as explained in subsection 4.1, are discussed.

- grid compatible self consumption
  The worst case is that the battery is fully loaded for the RPF scenario and fully discharged in the HLF-case. The resulting diversity factors for implementing BSS in the grid planning are listed in Table 11 and result in a neutral behaviour of the BSS. The operation strategy direct loading and schedule as used in the projects Strombank and MSG EUREF (see Table 8) can be mentioned as an example.

- grid supportive self consumption
  For the HLF the same as for grid compatible BSS applies, as the battery might be fully discharged as well. The difference arises for the RPF. In this case the battery is used to mitigate the reverse power flow caused by DG with peak shaving. The peak shaving threshold can be either fixed or adaptive as in the case of forecast based charging and discharging. For the projects listed in Table 8 that use a forecast based operation mode a peak shaving functionality is implemented. Nevertheless, the rated power of the BSS might be higher than the power used to mitigate the power at the PCC, which is the case in the EEBatt project where the energy to power ratio of the BSS is 1:1. In this case, the diversity

factor is the quotient of the power used for peak shaving purposes and the rated charging power of the BSS. For example, for the project SmartOperator (pure peak shaving) the diversity factor is 1, but it is < 1 in the EEBatt project (forecast based SC). This operating strategy can solve over-voltage (cable) and thermal issues (cable and secondary transformer) if the BSS is installed in the same LV feeder as the DG causing them. The thermal load of the primary transformer is reduced in any case independently of the allocation of loads, DG and BSS, as the peak of the RPF is mitigated in any case, if a diversity factor of > 0 for the BSS is reached.

- system compatible primary control reserve
  It can be deduced from Fig. 18, that a BSS providing PFC might discharge or charge with its full rated power at any moment. Depending on the system architecture, some BSS have the capability to be overloaded, as reported in [190] for VRF (100 % over-loading), in [184] for LIB (30 % over-loading for 15 min), and in [199] (25 %) also for LIB. In a worst-case scenario, the normal operation together with the application of the degrees of freedom as described in subsection 5.3 can lead to a diversity factor > 1. Depending on the allocation of the BSS it might reduce the hosting capacity of DG of the affected grid as this operation strategy tightens the over-voltage and over-loading issues. All projects listed in Table 10, except the SmartPowerFlow project, where the BSS behaves in a system supportive way fall into this category.

[Fig. 18 about here.]

- system supportive primary control reserve
  The diversity factor for this operating strategy is the same as for the gird compatible behaviour, as the active power flows are the same. The difference here is that a reactive power control is used to solve over-voltage issues.

[Table 11 about here.]

In the traditional distribution grid planning reactive power control is usually not considered and only a fixed $cos\varphi$ can be taken into account as only one time-step for the two worst case scenarios is calculated. In a grid/ system compatible behaviour $cos\varphi$ may be set to 0 and in a grid/ system supportive behaviour to the maximum favourable value from grid perspective. Nevertheless, this issue has not been analysed systematically yet and may lead to wrong results if the method of the traditional planning is applied. For an accurate simulation of a reactive power control, a load flow analysis based on time series has to be applied.

It can be concluded that the traditional planning method of passive distribution systems for large scale BSS will lead to over-capacities and uncertainties concerning the reactive power flows. Therefore, CIGRE promotes the shift to active distribution systems as defined in CIGRE WG C6.11 [200], which will incorporate

DG and BSS in a more active way than the fit-and-forget approach which is currently used and will allow to apply new planning approaches more efficiently. This transition is described in detail by [46]. As discussed in subsection 4.1, BSS, as well as DG and the distribution grids need to be modelled to calculate time-series and derive suitable probability density functions. Depending on the application and technology different time-steps need to be realised in these models [46]. In [201] it is shown that for SC the operation strategy should be simulated at least in one minute time-steps to avoid short-term feed-in peaks. For PCR the resolution has to be even higher and one second time-steps seem appropriate, in order to incorporate all degrees of freedom described in subsection 5.3 properly.

As for the reactive power control current studies focus on two main directions: a central approach using an AC OPF, such as [71], or an autonomous voltage control, as for example a Q(V) control [41]. It seems as if autonomous voltage control strategies are the more favoured solution at the moment as the technical standard for connecting BSS and DG in MV and LV are aiming in this direction [31].

The challenges of future investigation lie in modelling BSS to calculate active and reactive power time series for different applications in order to apply them for new planning approaches in active distribution systems.

6. Conclusion

In this paper, traditional approaches and recent advances in distribution grid planning alongside with alternative possibilities to traditional grid extension with large scale battery storage systems are described. In addition the German energy storage market is analysed and the operation strategies of the two most profitable applications, self-consumption maximisation and primary frequency control, are described in detail after an extensive literature review. The main findings and contributions of the paper are:

- A clear methodology for grid extension measures in distribution grids has been presented.
- Most of the new approaches for distribution grid planning use deterministic models and do not consider reliability issues. There is a great variety of these models with their respective pros and cons that have to be considered for the given planning task. Nevertheless, it is shown that the over-sizing problem remains even for advanced grid planning methods if worst case scenarios are applied. Therefore, there is a great need for detailed models to generate combined active and reactive power flows of BSS that are market-driven and grid/ system supportive at the same time.
- An analysis of 20 potential revenue streams for BSS shows that the primary control reserve market holds the highest revenue potential for market based applications, whereas the highest cost reduction potential lies in the maximisation of the self-consumption using renewable energies, especially for households.

- As suitable options for the maximisation of self consumption the operation strategies direct loading, schedule mode, peak shaving, and prognosis based loading were identified. Additionally, several large scale BSS projects in Germany applying those strategies were presented. The prognosis based operation strategy with a peak limit restriction seems to be the most promising, as it leads to manageable curtailment losses, especially if the feed-in limit is reduced in the future. Within the forecast based strategies the adaptive forecast algorithm combines the advantages of autonomy from external forecasts with their accuracy. Nevertheless, due to additional fees and taxes applying for community electricity storages, this business case is hard to transfer from residential to large scale storages. Besides a need of revising the existing legal framework in order to make CES economically feasible, there is also a need for future research regarding this application. Nonetheless, it seems especially interesting as in the near future PV systems, that have reached the end of their 20 year period of feeding into the grid with a fixed feed-in tariff, can be used for this applications with an extreme low LCOE.

- Primary frequency control seems to be the most promising business case for BSS in Germany at the moment. Although the net present value is just becoming positive, there is still a great challenge to make it profitable. Although the degrees of freedom help to achieve this goal, research is still necessary to determine the different benefits of these options, especially for VRFB, since most of the BSS used for primary frequency control are lithium-ion batteries.

- The task to implement BSS in (traditional) distribution grid planning is also subject to ongoing research. At the moment many of the studies only consider active power flows and worst case assumptions are applied. If traditional planning methods for passive distribution systems are applied for large scale BSS, over-capacities will probably be the result. In order to evaluate the potential of BSS to behave in a grid supportive manner, power flow simulations considering operation strategies for active and reactive power control for different time scales depending on the application have to be conducted.

In conclusion, it is worth pointing out that large scale BSS are becoming economically feasible in Germany, however there is a lack of planning guidelines for DSO to integrate the BSS in their grid. Furthermore, not all the applications and operating strategies are mitigating the problems of the DSO that arise with increasing penetration of DG. Future studies should concentrate on combining a profitable and a grid supportive behaviour into one operation strategy, otherwise the implementation of BSS in distribution grids might lead to further grid extension instead of grid relief.

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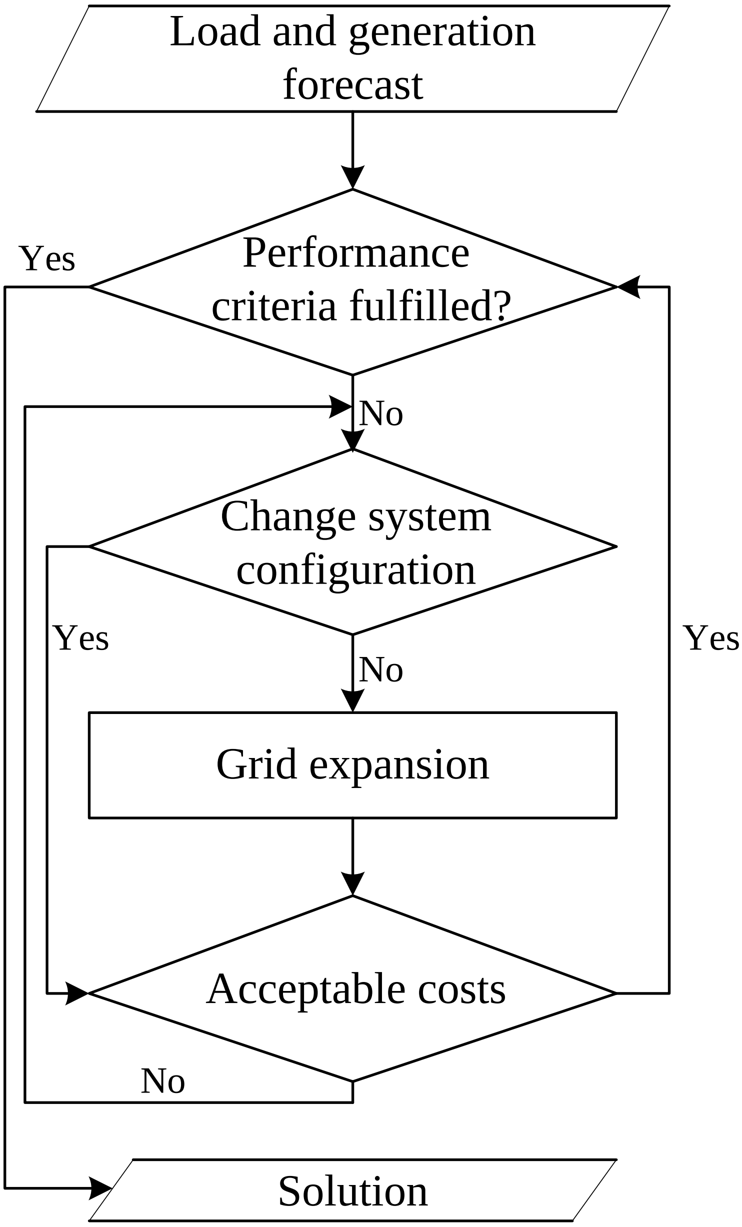
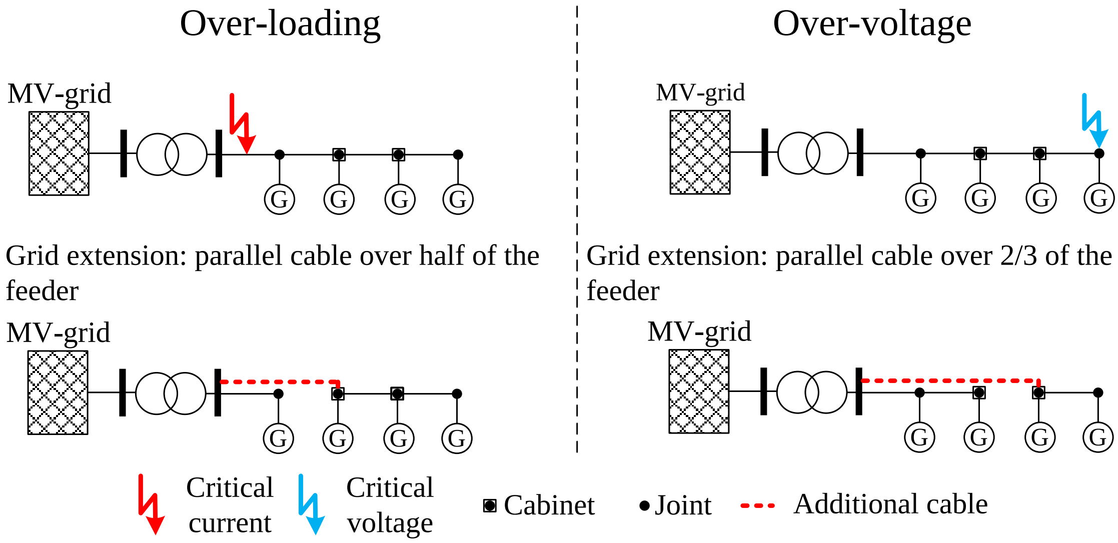


Fig. 1. Distribution grid schematic [202, 17] (adapted)



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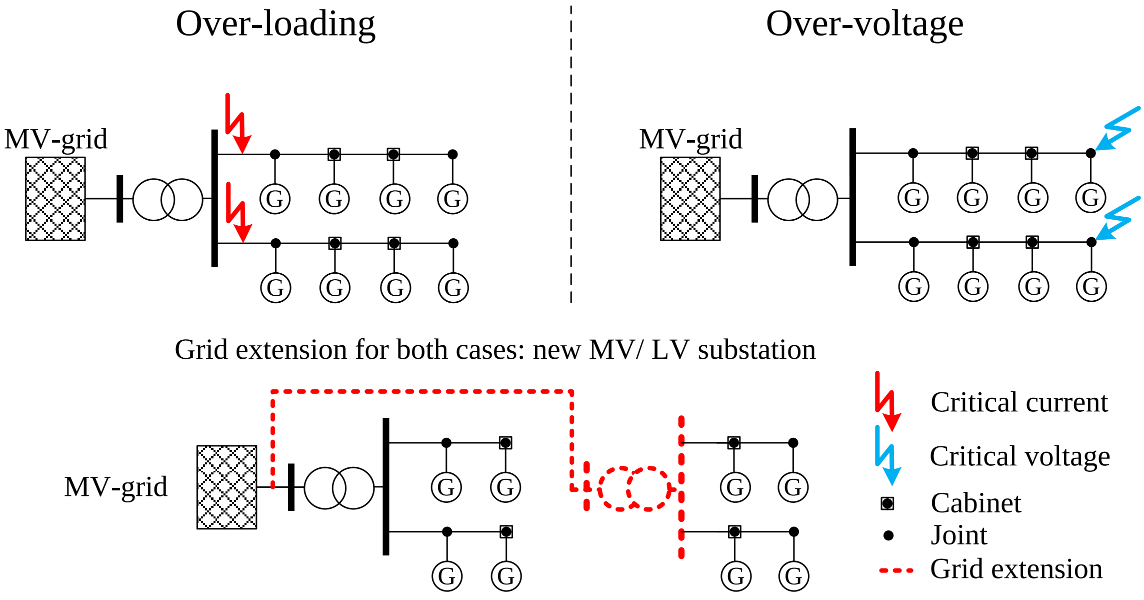

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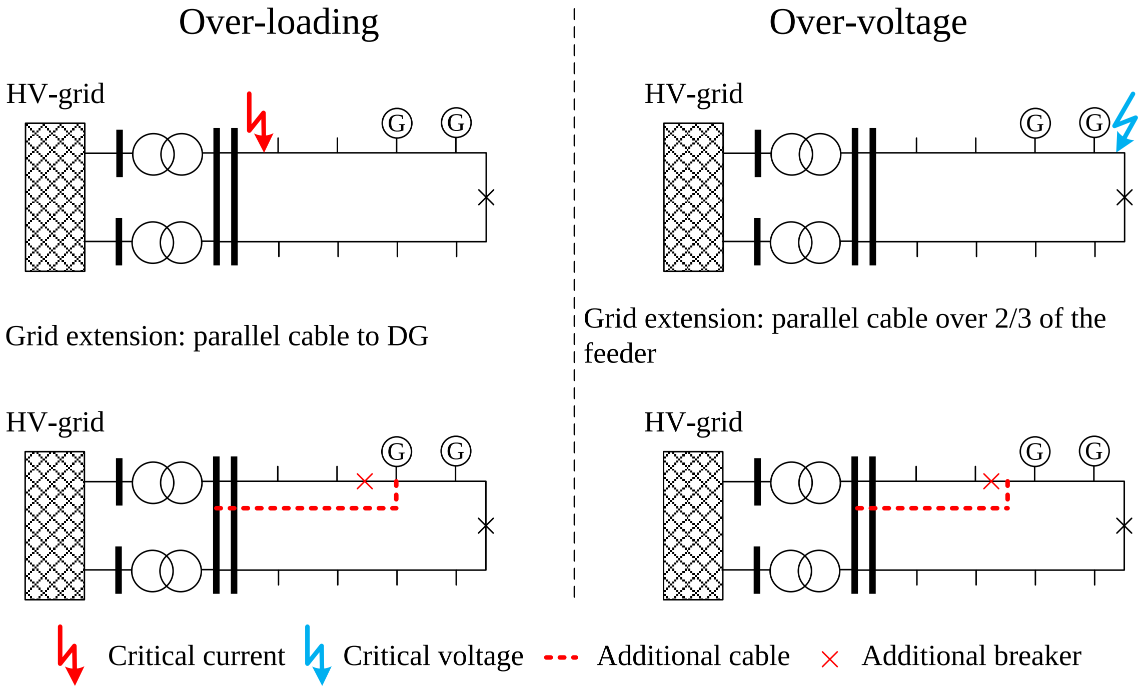

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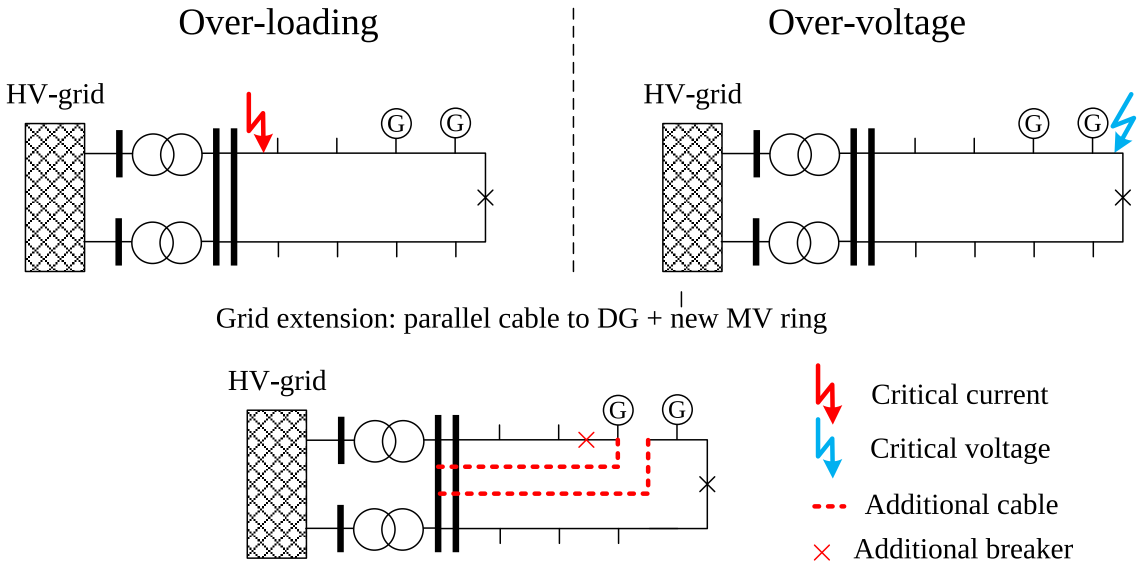

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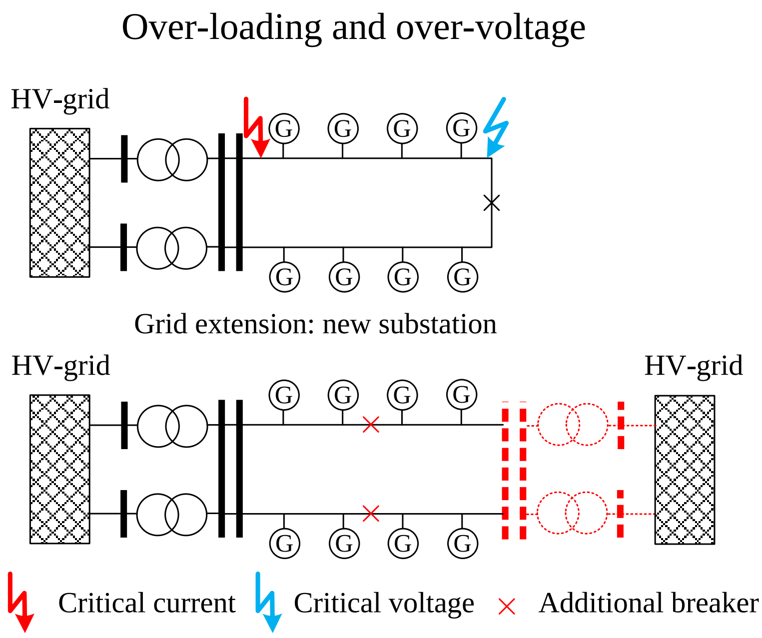

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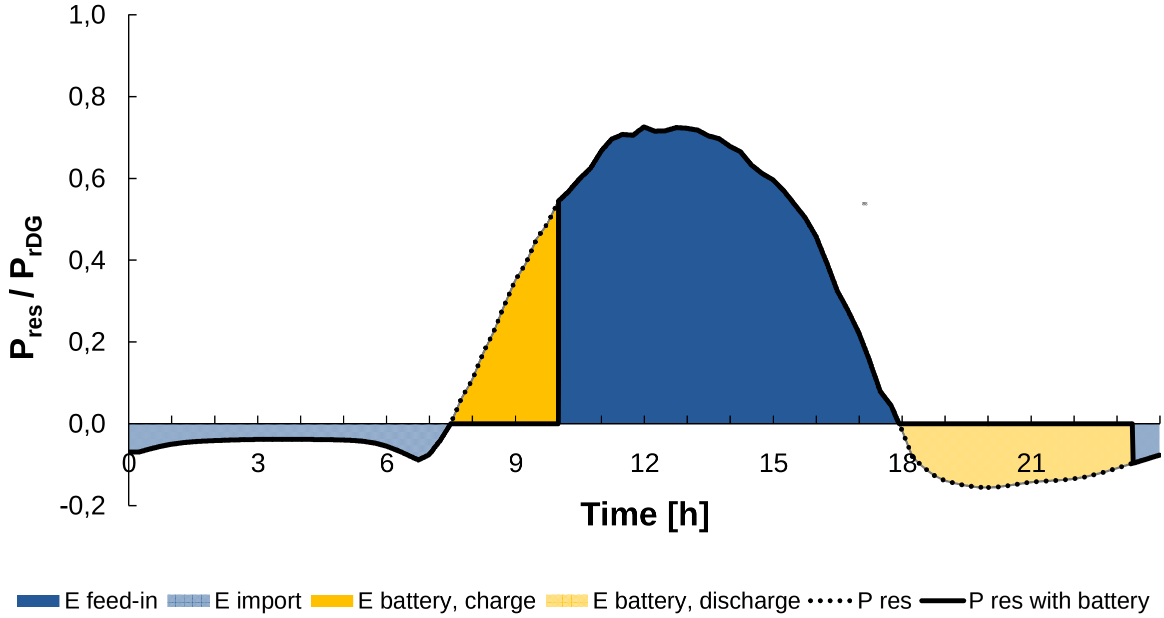

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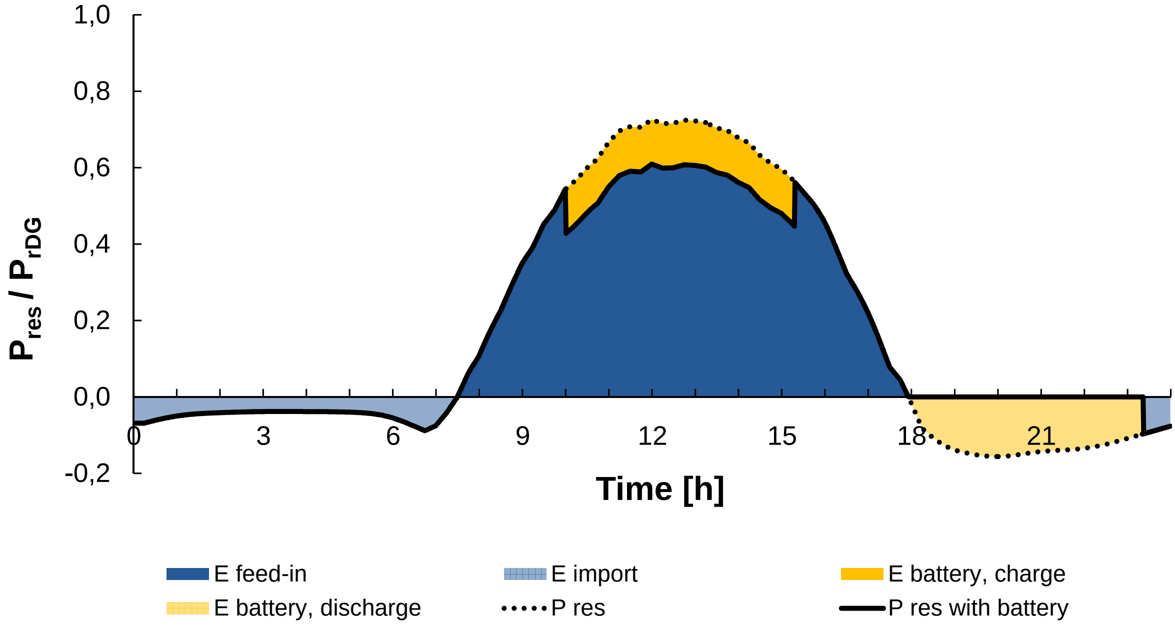

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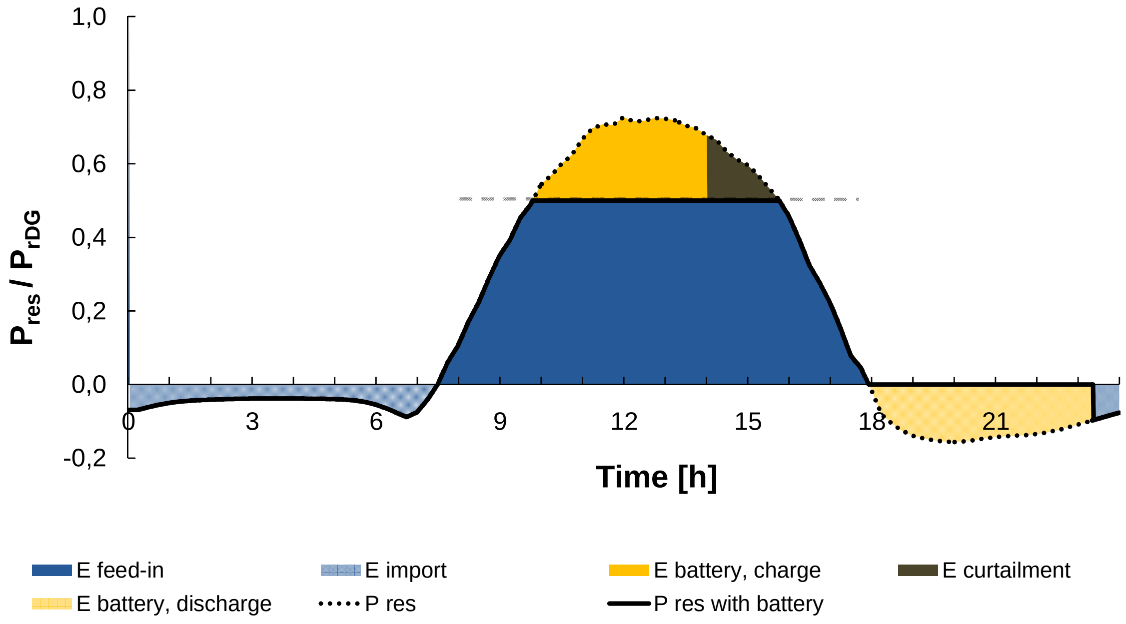

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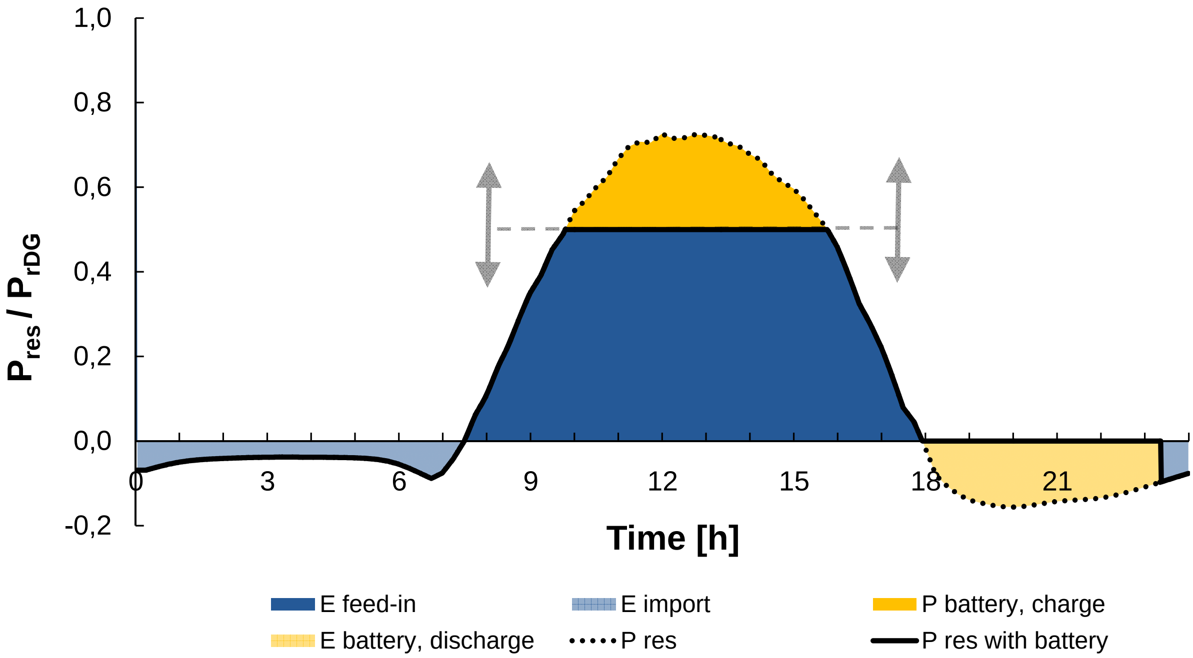

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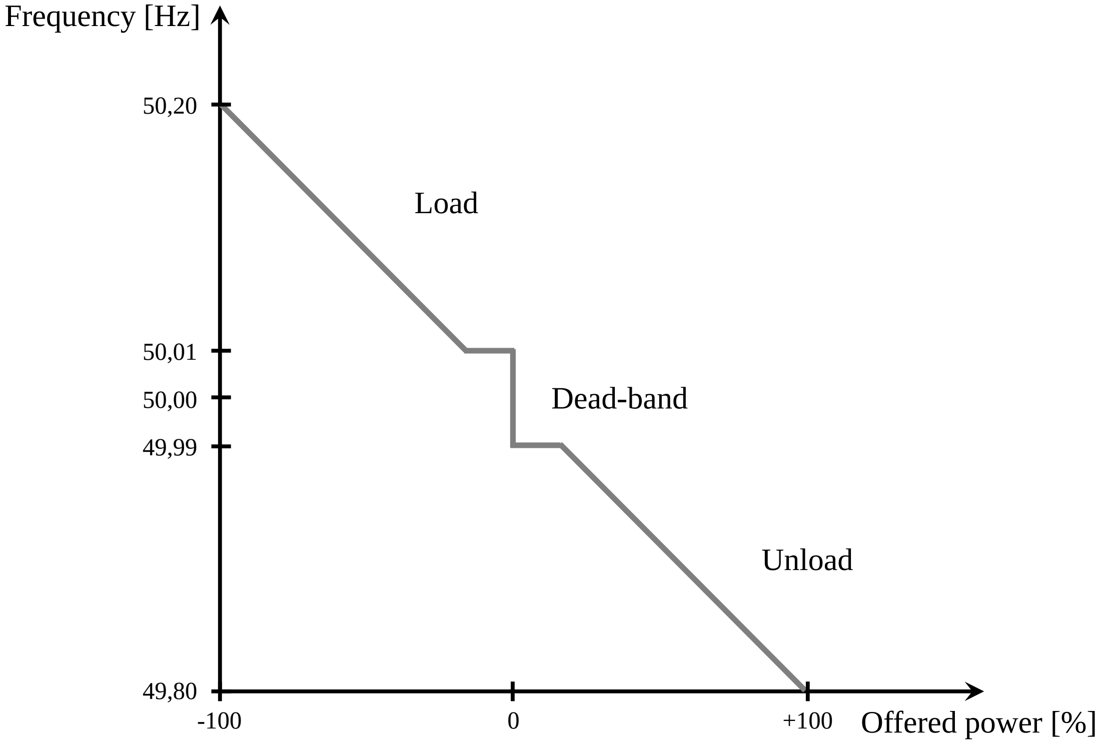

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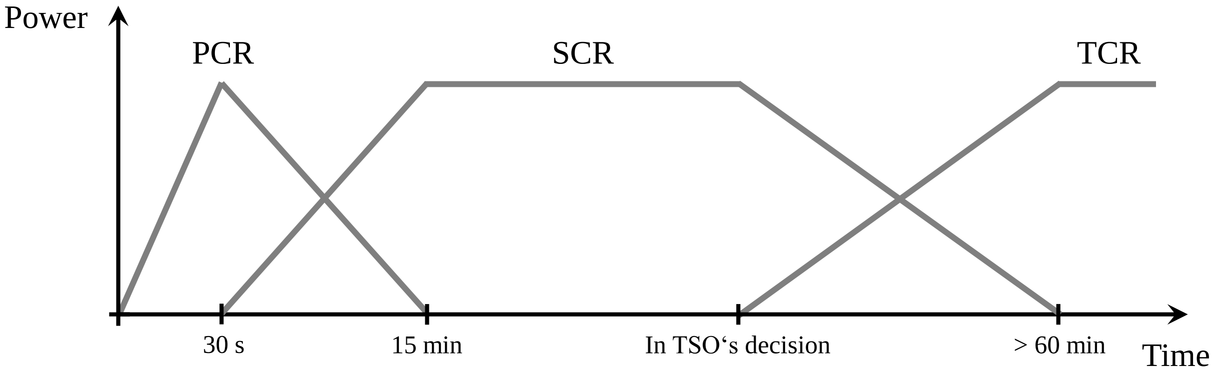

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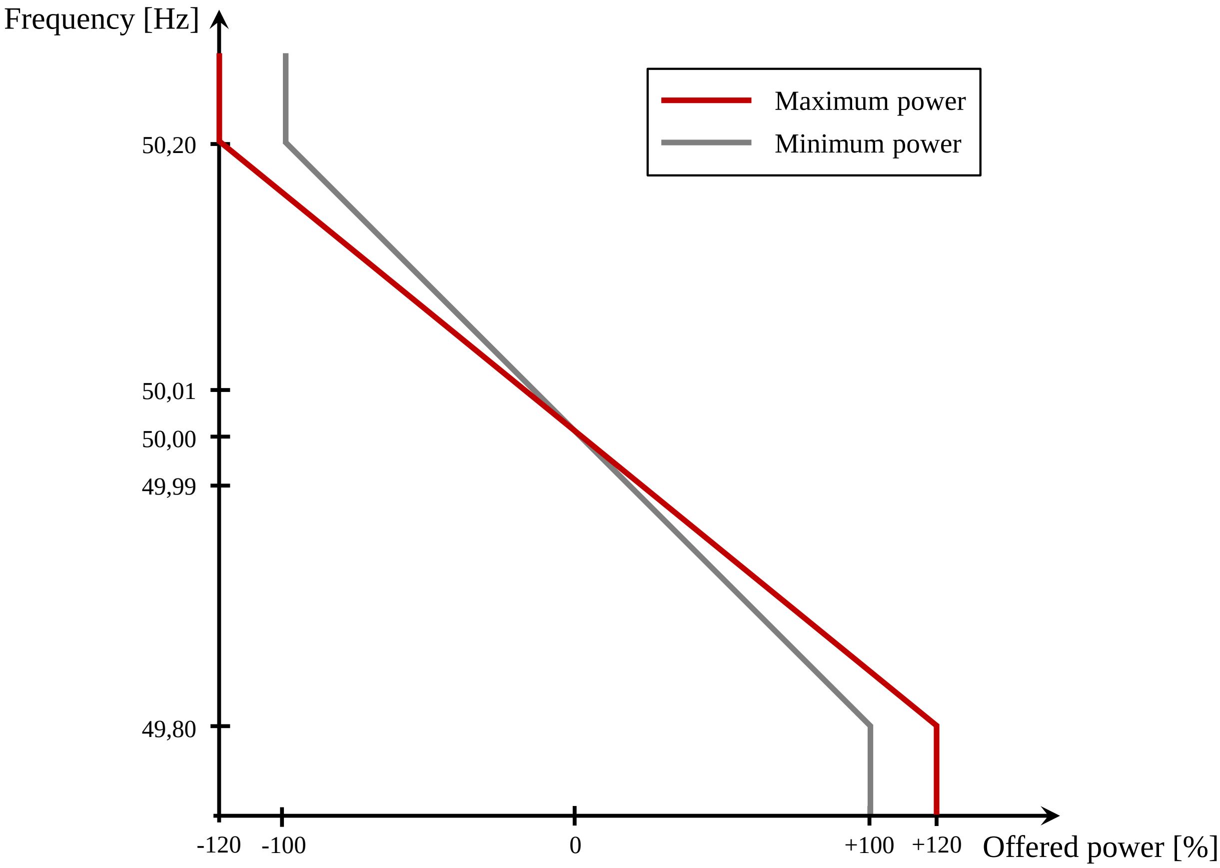

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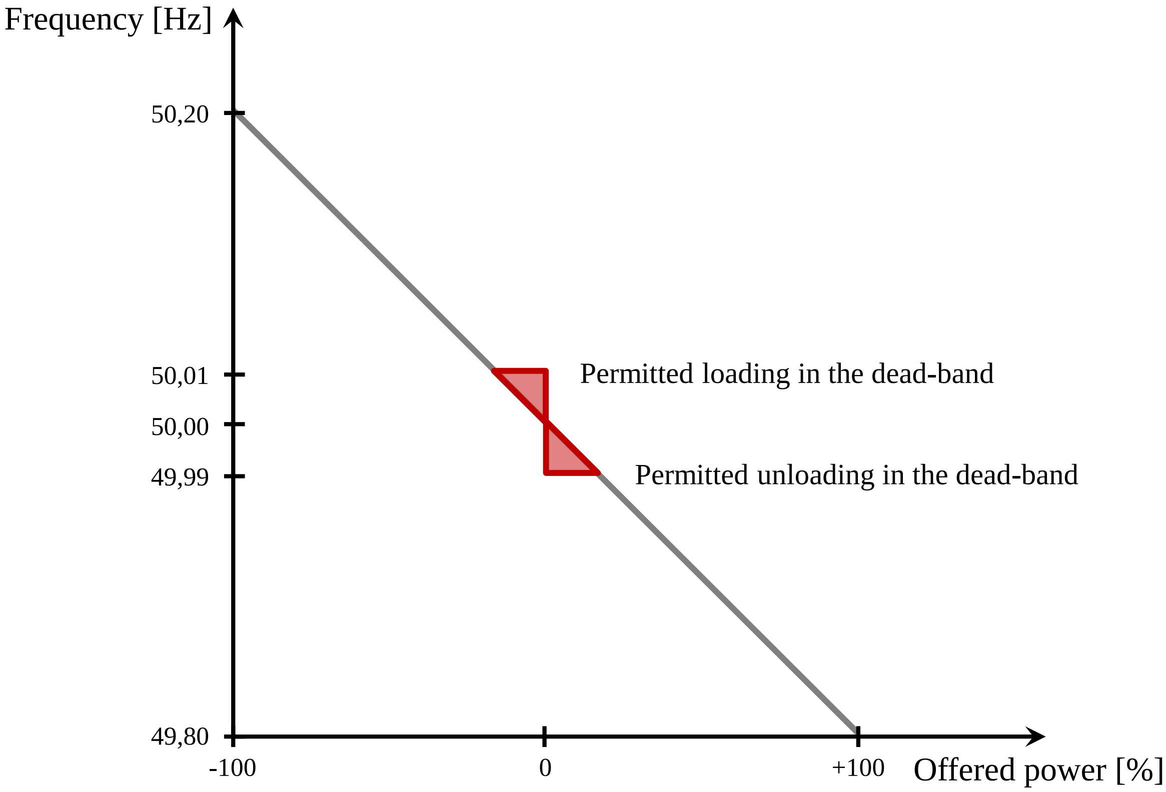

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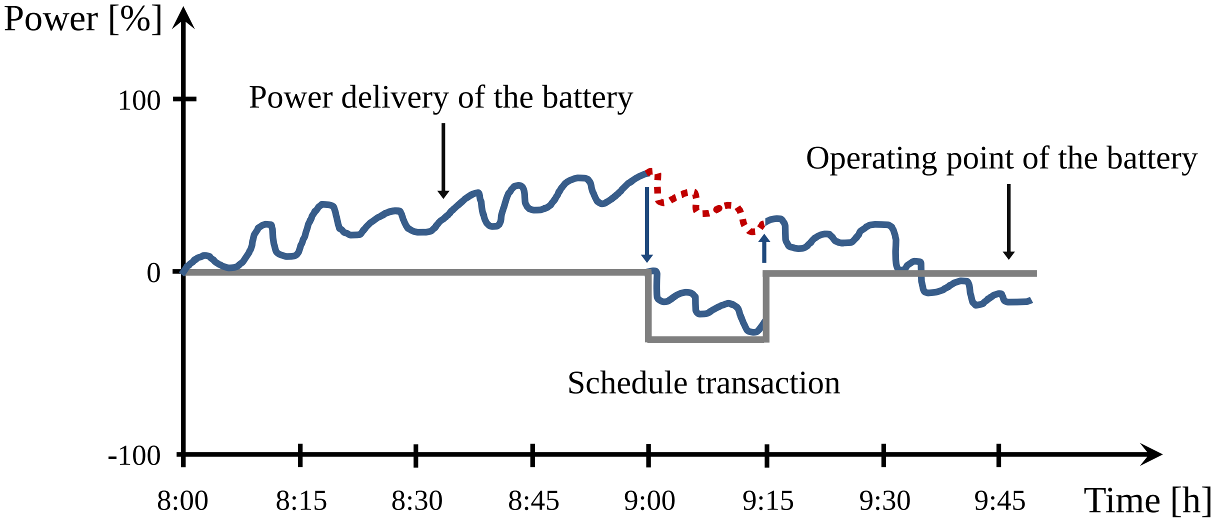

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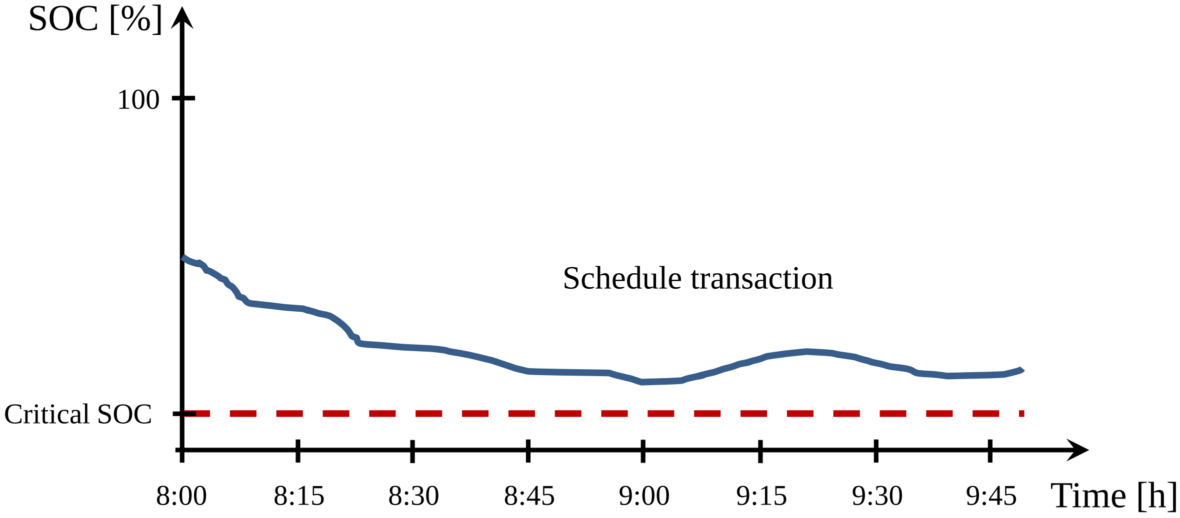

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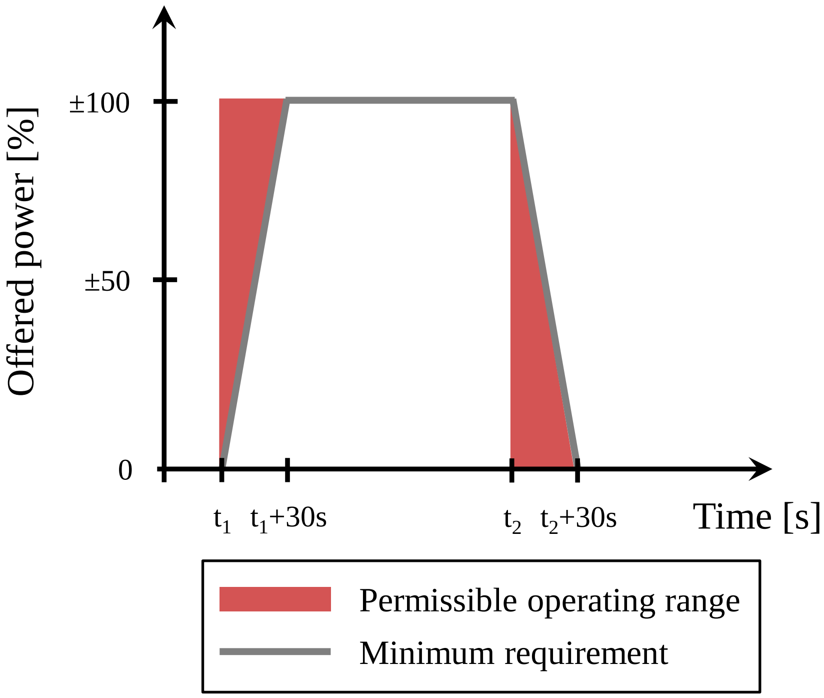

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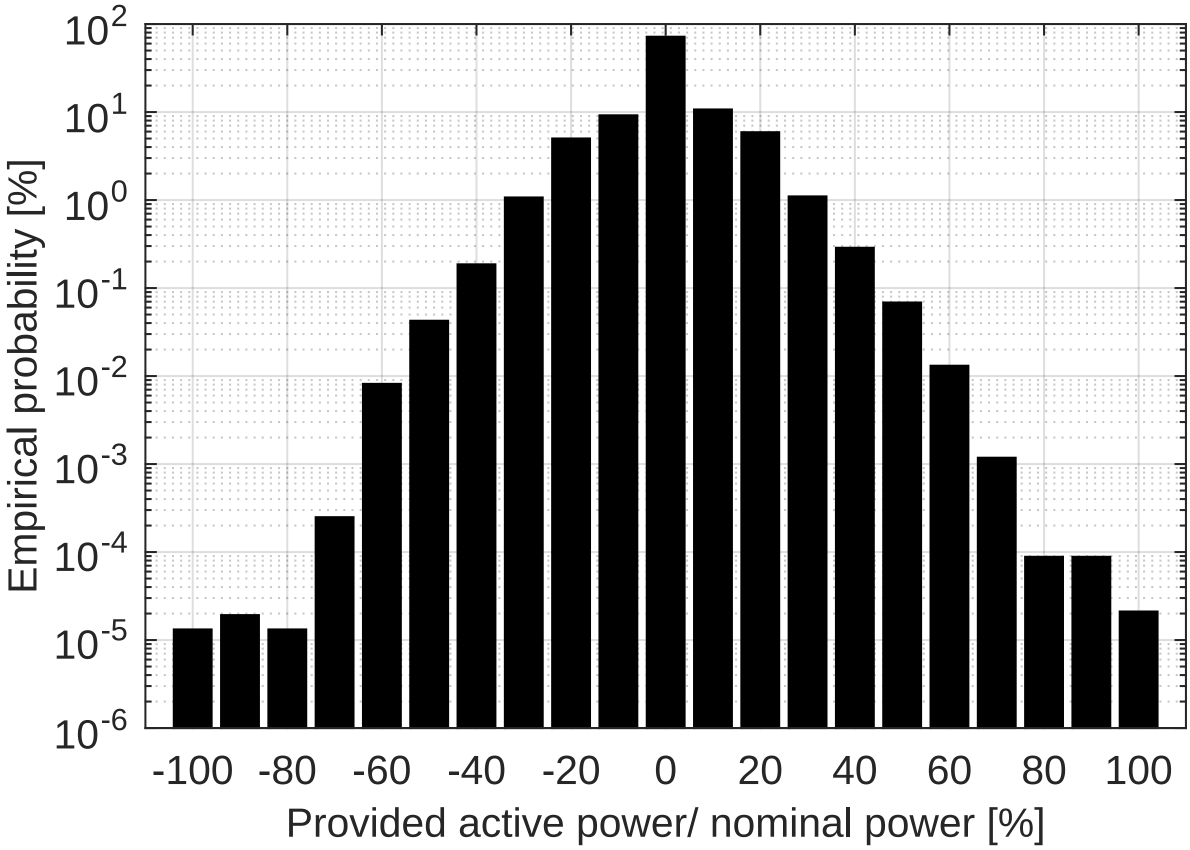

Fig. 18. Statistical requests of PCR power in the UCTE grid [103] (adapted)

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Table 1. Equipment load factors [17]

Equipment	Load factor of S_r Heavy load flow	Load factor of S_r Reverse power flow
LV-cable	max. 100 %	max. 100 %
MV/LV tran.	max. 100 %	max. 100 %
MV-cable	max. 60 %	max. 100 %
HV/MV tran.	max. 60 %	max. 100 %

Table 2. Diversity factors for generators connected in MV or LV [7, 17, 53, 54]

	Wind	PV	BM	Water
HLF	0 [17]	0 [7, 17, 53, 54]	0 [17] 0.6 [7]	1 [17]
RLF	0.95 [7] 1 [17]	0.85[17, 53, 54] 0.89 [7]	0.98[7] 1 [17]	1[17]

Table 3. Coincidence factors for loads connected in LV and MV [17, 55]

	Load (LV)	Load (MV)	C. load (MV)
HLF	1 [17]	1 [17]	1 [55]
RPF	0.1 [17]	0.15 [17]	0.5 [55]

Table 4. Standard equipment for grid extension

Equipment	dena [17]	Stetz et al. [62]	Idlbi et al. [64]	Ackermann et al.[30]
LV-cable (NAYY)	4x150 mm^2	(3x150; 3x240) mm^2	4x150 mm^2	4x150 mm^2
MV/LV tran. ($S_{r,t}$)	630 kVA	(400; 600; 800) kVA	(400; 600; 800; 1000) kVA	630 kVA
MV-cable (NA2XS2Y)	3x1x185 mm^2	-	-	3x1x240 mm^2
HV/MV tran. ($S_{r,t}$)	40 MVA	-	-	-

Table 5. New distribution grid planning approaches with DG integration

	without reliability		with reliability under normal conditions		with reliability under contingency conditions	
	deterministic	uncertain	deterministic	uncertain	deterministic	uncertain
mixed integer	[73][b], [77][c], [76][c], [72][a,b] [78][d], [86][f], [63][e], [71][a,d]	[75][b,z], [91][y] [92][y]	[85][e], [83][e] [84][e]	[82][d,z] [74][e,z] [79][d,z]	-	[80][d,z]
continuous	[72][h], [71][h]	[89][g,z]	-	-	[81][d]	-

[a]MILP, [b]MINLP, [c]BD, [d]GA, [e]PSO, [f]ES, [g]DP, [h]NLP, [y]possibilistic, [z]probabilistic

Table 6. Energy and power related applications for BSS [101]

Application	Nominal power P
Energy related:	
Peak shaving	0.1 MW to 10 MW
Load levelling	1 MW to 100 MW
Energy arbitrage	50 MW to 500 MW
Power related:	
Frequency control	1 MW to 30 MW
Voltage regulation	1 MW to 30 MW
Power quality regulation	1 MW to 30 MW
Bridging power	1 MW to 30 MW

Table 7. Potential benefit estimations for the German electricity market in 2014

	Application	Benefit potential	Notes
Market based revenues	day ahead market	0.00-51.29 EUR/MWh [203]	based on mean hourly rates
	intra-day market	0.00-69.10 EUR/MWh [203]	
	PCR	17.60-20.01 EUR/MWh [204]	min.= average power price; max.= average marginal power price; potential for SCR and TCR higher because energy price not included
	SCR(pos.)	7.87-11.91 EUR/MWh [204]	
	SCR (neg.)	11.83-53.17 EUR/MWh [204]	
	TCR (pos.)	0.95-1.58 EUR/MWh [204]	
	TCR (neg.)	5.72-8.63 EUR/MWh [204]	
Bilateral contracts	voltage support	0.60 -8.70 EUR/Mvarh [205, 206, 207]	based on available TSOs-price sheets
	system restoration	6.85 EUR/MWh [208]	high uncertainty, based on US-data
	redispatch	9.72-47.54 EUR/MWh [209]	based on marginal cost of conventional power plants (= cost-based redispatch) min.= marginal costs nuclear; max.= marginal costs natural gas
Cost reduction	UPS	12.72 -27.72 EUR/MW/h [210]	high uncertainty, based on US-data
	BGM: reBAP (pos.)	0.01-43.05 EUR/MWh [16]	max.= average volume-weighted reBAP prices; potential ascending
	BGM: reBAP (neg.)	0.01-9.39 EUR/MWh [16]	
	ECM (households)	9.00-98.00 EUR/MWh [211, 212, 213, 214]	exemplary cost analysis of the "big four" (E.on, RWE, Vattenfall and EnBW); difference between high and low tariffs
	ECM (industry)	10.7 EUR/MWh [203]	based on day-ahead market data: average price block-contracts, peakload (hours: 09-20) and offpeak (hours: 21-08)
	RPM	13.00 EUR/Mvarh [117]	based on capacitor bank prices by [117]
	demand management	15.00 EUR/MWh [206, 215, 216, 217]	based on TSOs power prices on the high voltage level <2,500 h/a
	RE SC (hh)	85.00-191.00 EUR/MWh [143, 218]	residential PV-system costs [143] and av. electricity costs for households [218]
	RE SC (ind.)	0.00-50.00 EUR/MWh [143, 144]	Based on LCOE of large scale PV [143] and el. price for large consumers [144]
	grid expansion relief	0.10-0.20 EUR/MWh [17, 219, 220]	grid expansion costs: costs based on the "Bundesländerszenario" [17]; grid asset lifespan 40 years; consumption in the distribution network 300 TWh

Table 8. Overview of recent large scale BSS projects to maximise self-consumption and peak shaving in Germany

Project name	LCOE; NPV ; profit/a	Generator(s)	Battery	Load(s)	RESCR	Operating strategy/ comment	Ref.
MSG EUREF	LCOE=0.52 EUR/kWh	$P_{PV} = 91kW_p$; $P_{wind} = 330kW$	**LIB:** capacity=78 kWh **PbB:** capacity=90 kWh **supercap:** capacity=3 kWh	Total yearly energy demand: approx. 400 MWh/a for office buildings	64%	direct loading/ all values for scenario 03	[153]
Strombank	Positive NPV, in case of no FIT and if no taxes and tariffs apply	$P_{PV} = 64kW_p$ $P_{CHP} = 16.5kW$	**LIB:** $P_{c./disc.} = 100kW$ capacity=100 kWh	14 households 4 industrial facilities	30%-60%	direct loading; prognosis based dis-/charging is planned	[154, 221, 222]
IRENE	no profit compared to traditional grid expansion	$P_{PV} = 20MW_p$; $P_{wind} = 23.5MW$ (2022)	**LIB:** $P_{c./disc.} = 70kW$ capacity=162 kWh	$P_{max} = 5.6MW$ (2022)	70% (2022)	peak shaving	[160, 14]
Fechheim	N/A	$P_{PV} = 90.5kW_p$	**LIB:** $P_{c./disc.} = 45kW$ capacity=230 kWh	16 households $P_{max} = 30kW$	100%	peak shaving	[162]
Smart Operator	N/A	$P_{PV} = 60kW_p$	**PbB:** $P_{c./disc.} = 30kW$ capacity=150 kWh	110 households	N/A	peak shaving	[163, 223, 165]
SmartRegion Pellworm	Profit: 150 kEUR/a (2013)	$P_{PV} = 772kW$; $P_{wind} = 330kW$	**LIB:** $P_{charge} = 560kW$ $P_{disc.} = 1000kW$ capacity=560 kWh **VRFB:** $P_{c./disc.} = 200kW$ capacity=1.6 MWh	20 households $P_{max} = 487kW$	93%	prognosis based dis-/charging; using external forecasts	[93], [71]
EEBatt	N/A	$P_{PV} = 300kW_p$	**LIB:** $P_{c./disc.} = 200kW$ capacity=200 kWh	50 households	25%	prognosis based dis-/charging; using persistence forecasts	[224, 151, 169]
Smart Grid Solar (Epplas-Hof)	N/A	$P_{PV} = 287kW_p$	**PbB:** $P_{c./disc.} = 72kW$ $P_{disc.} = 72kW$ capacity=330 kWh	16 households	N/A	prognosis based dis-/charging	[225, 179]

Table 9. Key parameters for the provision of primary control reserve [27, 226, 227]

Max. frequency response insensitivity	±10	mHz
Full activation frequency deviation	±200	mHz
Full activation time	30	s
Tendering period	1	week
Min. bid size	±1	MW
Time availability	100	%

Table 10. Overview of recent large scale BSS projects for primary frequency control in Germany, based on [121] and contact with the BSS owners

Project name	BSS type	Rated power P_r [kW]	Duration at P_r [HH:MM]	Commissioning date	Funding source	Pre-qualified	Lifetime [a]
WEMAG Younicos Battery Park [a]	LIB	5,000	1:00	16/09/2014	federal/ private	yes	20
Younicos and Vattenfall Project: Sodium Sulfur / Lithium Ion	NaSB/LIB	1,000/ 200	6:00/ 1:00	01/12/2012	federal/ private	yes	20
M5BAT (Modular Multi-Megawatt Multi-Technology Medium-Voltage Battery Storage)	PbB/LIB	5,000	1:00	mid 2016	federal/ private	no	2
Feldheim Regional Regulating Power Station (RRKW)	LIB	10,000	1:00	21/09/2015	federal/ private	no	10+x
Bosch Braderup ES Facility	LIB/ VRFB	2,000/ 325	1:00/ 3:50	11/07/2014 // 15/09/2014	private	no	15
1.3 MW Battery in Alt Daber	advanced PbB	1,300	0:40	10/2014	federal/ private	yes	15
Bosch Second Life Batteries	LIB	2,000	1:00	Q3 2016	private	no	10
REDMONDIS Electrorecycling Plant	LIB	13,000	1:00	mid 2016	private	no	10+x
3 MW Battery Storage - Dörverden, Germany - Statkraft	LIB	3,000	N/A	15/12/2015	N/A	N/A	N/A
LESSY	LIB	1,000	0:42	01/02/2014	federal	yes	N/A
90 MW Energy Storage - STEAG GmbH	LIB	6 x 15,000	1:30	mid 2016 to early 2017	private	no	N/A
SmartPowerFlow	VRFB	200	2:00	02/09/2015	federal	no	1

[a] First stand alone battery in Europe, according to [228]

Table 11. Diversity factors for BSS applied for SC and PCR

	HLF	RPF
grid compatible SC	0	0
grid supportive SC	0	$(0\text{-}1)_{charge}$
system comp./ supp. PCR	$(1+x)_{charge}$	$(1+x)_{disch.}$