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Techno-Economic Assessment of Flexibility Options Versus Grid Expansion in Distribution Grids

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***Abstract*—In this paper five different flexibility options are analysed from a techno-economic perspective as alternatives to traditional grid expansion for a specific distribution grid in Germany. The options are: two reactive power control strategies with photovoltaic inverters (as a function of the power feed-in, or of the voltage at the connection point), one residential and two large scale battery storage applications (primary control reserve with autonomous reactive power control or self consumption maximisation strategy with autonomous reactive power control). For the pilot grid located in Southern Germany a photovoltaic expansion pathway is determined. The main goal of this work is to quantify the grid expansion actions that can be avoided by applying these five flexibility options for the assumed expansion pathway, focusing on large scale battery storages. It is shown that the five flexibility options increase the hosting capacity for PV systems, compared to a scenario without, by up to 45 %. Furthermore, the results of the economic assessment indicate that the analysed flexibility options might be a viable alternative to traditional grid expansion as all of them show a cost reduction potential for the pilot region. These results could encourage DSOs to consider the integration of additional PV and battery storage systems not as a problem which triggers grid expansion, but as part of the solution reducing future grid expansion costs.**

***Index Terms*—Battery systems, cost-benefit analysis, distribution grid planning, flexibility options, photovoltaic**

I. Introduction

In Germany, most of the rising amount of decentralised generators are installed as photovoltaic (PV) systems in distribution grids [1]. These grids were not designed to cope with decentralised generators and therefore mainly over-voltage (OV), but also equipment over-loading (OL) issues arise.

Traditional grid reinforcement, based on worst case scenarios that may occur rarely, is normally applied by the distribution grid operator (DSO) to avoid OV and OL [2]. The drawback of this grid planning procedure is the potentially large investment in infrastructure with a low utilisation rate. Therefore, technically and economically efficient control strategies that increase the hosting capacity for distributed generation in distribution grids, as defined in [3], are of major interest.

In contrast to Active Network Management, as defined in [4], the focus of this work is set on autonomously operating strategies that avoid OL and OV, defined hereafter as (grid planning) flexibility options. In this context autonomously means that the operating strategies rely entirely on locally measured values and need no communication infrastructure. Further, [4] focuses on wind power integration, whereas this paper focuses on PV and batteries. The following flexibility options are compared to traditional grid expansion: cosφ(P)-control (state of the art in most European countries) and Q(V)-control of PV systems (voltage droop control), residential storage systems (RES) and grid/system supportive applications of large scale battery storage systems (BSS), as defined in [2]. The applications of the BSS are system supportive primary control reserve (PCR) and grid supportive community electricity storage (CES) [5]. The last two applications are reported to be the most common and profitable ones in the German energy market, especially PCR without additional reactive power control, due to the mature regulatory framework [2], [6], [7].

However, none of the publications [8], [9], [10] consider the possibility to peruse a viable business model using an active power operation based strategy and additionally a reactive power control to increase the hosting capacity of a distribution grid, in spite of the recommendation of [11] to use BSS as Volt/Var control devices. At first glance it seems counter-intuitive that a BSS, which in the worst case could charge or discharge at a disfavourable moment (e.g. by discharging the BSS providing frequency dependant PCR, to which the DSO has no influence, at the same time at which the PV systems act as generators) and which therefore contributes to worsen the OL and OV issues, instead of worsening the issues might ease them. The hypothesis of this work is that by connecting the BSS to the LV busbar of a secondary transformer (R/X-ratio at the point of common coupling tipically around 0.3-0.5), the positive effect of the Q(V)-control on the voltage on all LV feeders can outweigh the additional negative effect on the voltage and loading due to the "unfavourable" behaviour of the active power. Thus, in radial LV-grids, especially the ones with long feeders, in which OV is the main driver for grid expansion, and for transformers in which the BSS doesn't cause OL, this BSS might reduce future grid expansion costs by regulating the voltage at the LV-busbar to which all feeders are connected.

To proof this hypothesis, a pilot case is analysed, in which different flexibility options with a focus on system/ grid supportive large scale BSS providing PCR or self-consumption maximisation are compared, following the recommendations of [11]. The unique contribution of this work is the analysis of BSS providing PCR and voltage control, as to the authors' knowledge neither DSOs nor the scientific community, consider them as a possibility to reduce future grid expansion costs in distribution grids. Thus, in this study it is analysed, if

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a BSS providing a combined PCR and voltage control is able to reduce future grid expansion by quantifying them for a pilot grid and showing that the supposed contrast of a business case driven and system/ grid supportive operation strategy of a BSS can be resolved in certain circumstances. In order to be able to better assess the findings, they are compared with the grid expansion costs caused by other (state of the art) flexibility options.

This analysis is part of a project called SmartPowerFlow (SPF) in which a 200 kW/ 400 kWh vanadium redox flow battery (VRFB) prototype based on the CellCube FB200-400 DC of the company Gildemeister energy solution, a 630 kVA inverter (SCS 630) developed by SMA AG and the SCADA software of the Younicos AG, has been developed. Thus, for the large scale BSS a VRFB is considered. The BSS models used for the assessment are based on measured data of a VRFB prototype developed especially for this task and are applied to a distribution grid of the DSO LVN, who is also a project partner, in southern Germany. The Reiner Lemoine Institute was the project coordinator and did the scientific evaluation. The prototype can operate in all four quadrants and is able to provide 200 kW active power and 400 kvar reactive power. Different operation strategies, especially PCR and CES along with reactive power control, have been integrated and tested [12].

This study is based on an extensive review of operation strategies for PCR and self-consumption maximisation of the same authors [2], [13], [14]. Derived from these reviews, the two technically and economically most promising system/ grid supportive operation strategies for PCR and CES were applied and analysed for the VRFB prototype [15]. In this paper, the impact of these two operation strategies on distribution grid planning are compared along with cosφ(P)-control and Q(V)-control of PV systems and RES. It builds upon the work of [16], which uses are very similar approach to evaluate flexibility options in LV grids, by adding a more realistic PV expansion pathway and battery storage systems to the cost-benefit analysis.

The paper is structured as follows: In section II the pilot region along with an assumed PV expansion pathway and the applied VRFB prototype is described. The methodology for a techno-economic assessment as well as the analysed flexibility options and their implementation in the model are presented in section III. The results are discussed in section IV and concluded in section V.

II. Model Region: Status Quo and PV Expansion Pathway

The grid model of the electrical grid in which the BSS is integrated, as well as a potential future PV system expansion pathway is presented in this section.

A. Grid model

The grid model consists of one medium voltage (MV) feeder of the distribution grid in which the VRFB is implemented. The MV feeder is connected to the HV via a 20 kV/ 110 kV transformer. The slack is located on the HV side of the transformer and its tap ratio is set to reach the voltage of 1.03 p.u. at the MV busbar at the substation. The total length of the MV feeder is 20.2 km and 44 low voltage (LV) grids are connected to it. Twelve of these LV grids form a village which is simulated in detail, whereas the other 32 LV grids are simulated in an aggregated way. The configuration of the grid consists of different elements: loads, generators, lines and transformers. These elements are distributed along the grid on 1208 nodes.

A total of 470 loads are connected to the grid, 441 individual loads are located inside the village and 29 accumulated loads in the surrounding area. A fixed power factor of 0.97 (inductive) is assumed for all loads.

The generated power on this LV grid consists on a group of different type of generators. Along the MV feeder there are 30 aggregated PV systems and 119 residential PV systems with a total power of 7.7 MVA. The PV power profile is based on normalised measured data of a PV system from 2013 and 2014 connected on a nearby village (10 km). In order to take into account different orientations, cloud impact etc. the simultaneity factor for the PV systems', is set to 0.85 [17].

Within the village there are 12 MV/LV transformers (20kV / 0.4kV), as depicted in Fig. 1. In the surrounding area the remaining 32 MV/LV transformers are connected to the same MV feeder. The loads, generators and transformers are connected via 1210 lines. For the twelve LV grids of the village (named after their MV/LV transformers T1 to T12), the R/X ratio varies between 2.3 (T9) and 5.9 (T7) with a mean value of 3.5.

B. Photovoltaic Expansion Pathway

In order to assess a hosting capacity for every LV grid, a future PV integration path must be determined. The method of [18] has been applied, to size, allocate and calculate the specific yield of future PV systems on rooftops using high resolution images. The expansion pathway is determined by a ranking, based on the specific yield of the PV system for each LV grid (highest yield is installed first). In 2013 2.1 MW_p were installed (status quo marked in blue in Fig. 1). The total technical PV potential of the village is calculated to 7.6 MW_p. A linear expansion is assumed until all additional systems are installed until 2040 are (marked in orange). In 2025 a total of 4.6 MW_p of PV systems will be integrated. Although the grid data bases on the status quo of the year 2013 the results of this paper are still valid, but may be regarded in the following context which is independent from the reference year: In the technical comparison of the flexibility options the expansion pathway is applied to asses the potential increase of hosting capacity for each flexibility options compared to a reference scenario. In the economic assessment the costs for a (more then) doubling of the PV capacity (from 2.1 MW_p to 4.6 MW_p) are calculated.

III. Methodology for a Techno-Economic Assessment of Alternatives to Grid Extension

In this section, a methodology is presented to compare the traditional approach of grid reinforcement technically

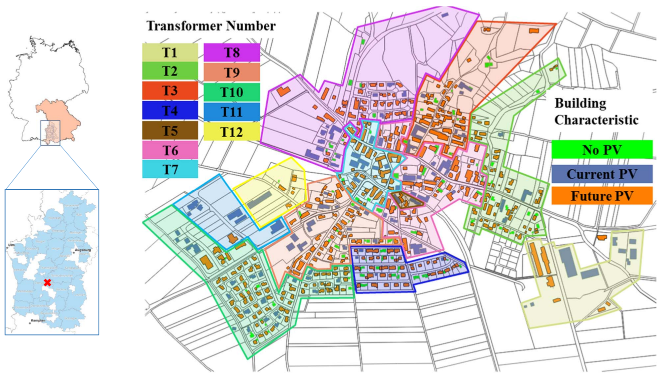

Fig. 1. Buildings in the village highlighted according to the MV/ LV transformers (LV grids) and expansion pathway of PV systems untill 2040.

and economically with flexibility options. The five flexibility options are applied with the following methodology:

- All PV systems in the pilot region apply a cosφ(P)-control.
- All PV systems in the pilot region apply a Q(V)-control.
- All PV systems in the pilot region are connected to a RES to maximise self-consumption.
- In every LV grid a BSS is implemented providing PCR and Q(V)-control, if it increases the hosting capacity.
- In every LV grid a BSS is implemented providing self-consumption maximisation as a CES and Q(V)-control, if it increases the hosting capacity.

The corresponding abbreviation for each flexibility option, their control strategies and control devices are listed in Table II for better overview. In the next section, the different flexibility options are explained in detail and their implementation in the simulation is presented.

A. Technical Comparison of the Flexibility Options

For the technical comparison, the decisive criterion to rise shares of renewable energy systems in distribution grids is the increase in hosting capacity. The maximum hosting capacity is reached when limits for OV at a grid node or OL of equipment are reached. For this study, the voltage related hosting capacity is limited by the permissible voltage band of ± 0.1 p.u. nominal voltage [19] for every time-step. The maximum threshold for OL is set to 100 % of the rated apparent power S_r for cables and transformers. Both restrictions are stricter than the technical requirements, but are applied in that strict form by the DSO LVN to have an additional buffer for measurement accuracy and thus assumed in this study.

In order to determine the increase of the hosting capacity, the total hosting capacity of the pilot region is determined, if no flexibility options are applied (reference scenario). Then, the same value is calculated using the various flexibility options. The increase of the hosting capacity is the difference between the two values.

Since the pilot region in the status quo has no OL or OV issues, PV systems are installed successively in the village following the expansion path described in section II-B. After the integration of each additional PV system, a steady state load flow analysis for one year is conducted with MATPOWER [20] (time steps: RES and cosφ(P) option minutes; PCR, CES and Q(V)) seconds). One simulation step takes around 0.2 s. To accelerate computation time the year was partitioned in 16 periods and calculated in parallel. The 1-min step models were calculated for whole years in 1-min steps, the 1-s models were calculated only for the worst case month, with the highest irradiation and the highest frequency deviations from 50 Hz (and thus the month were the OL and OV issues arise) in 1-s steps. The rest of the year was calculated in 1 min-steps (average values). This results in total in six different cases: five different cases for the flexibility options and the reference case.

In every time-step it is checked whether OL or OV limits are violated in one of the 12 LV grids. If this is the case, the hosting capacity of the LV grid is reached and the expansion of PV systems in this LV grid is stopped.

B. Economic Comparison of the Flexibility Options

The economic analysis is based on the PV expansion pathway until 2025. The future PV systems are integrated into the electrical grid model according to their prognosticated year of construction. If, as a result, OV or OL occurs in the load flow calculation, the state-of-the art grid expansion action are applied as a heuristic for the worst case time step of the year [8]: An OV issue is solved by installing a parallel NAYY 150 mm^2cable from the distribution substation to the next distribution cabinet over 2/3 of the line length. A critical OL of a line is solved by installing a parallel line till the next distribution cabinet, starting to search from half of the line on. If more than one line is affected, 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 630 kVA transformer (the method is described in detail [2]). If OL or OV is not solved by these actions the solution of [21] is taken into account. It implies adding a NAYY 240 mm^2 line from the MV/LV transformer directly to the point of common coupling (PCC) where the problem appears, to solve the remaining issues. The worst case time step of the year is identified by running a yearly load flow simulation as described in section III-A.

In this way, the total technical PV potential of 4.6 MW_p for the year 2025 from Fig. 1 can be reached in any case. This is different to the methodology for the technical comparison in which for every flexibility option a different amount of PV-systems are integrated until the maximum hosting capacity is reached.

The costs of the scenarios are calculated using the net present value method for the period 2013-2050. All costs are discounted for the reference year 2013 using a discount rate of 4%. The installation costs applied in the calculation are listed in Table I. A lifetime of 40 years is assumed for cables and 45 years for transformers respectively and their residual values in 2050 are taken into account.

The operating costs consist of the grid loss costs and the costs of the reactive power supply of the large BSS, as it is

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assumed that the DSO reimburses the cost for the reactive power supply to the BSS operator. It is assumed that the grid status achieved in 2025 will remain unchanged until 2050. In this way it is possible to compare the cost of the various flexibility options with the pure grid expansion for the period 2013-2050, as these options may increase or decrease the operating costs. For the grid losses, 64 EUR/MWh are agreed with the DSO of the pilot region. The cost for the additional energy required to provide reactive power control is set to 56 EUR/MWh for the large scale BSS [15].

In the case of the cosφ(P) and Q(V)-control of PV systems, costs for lost profits are considered if the inverter has to reduce the active power due to the reactive power control (see section III-C). These costs are set to 123.1 EUR/MWh, which represents the missed feed-in tariff [22]. Investment costs of BSS or PV systems are not considered, as within this study it is assumed that the cost burden is taken by a third party investor perusing a business model.

TABLE I
ASSUMED CAPITAL EXPENDITURES FOR THE AUTOMATED GRID EXPANSION, BASED ON [8] AND [21]. CABLE COSTS INCLUDE EARTHWORKS.

Equipment	Sizing	Costs
NAYY	150 mm^2	60 kEuro/km
NAYY	240 mm^2	65.5 kEuro/km
Oil-immersed transformer	630 kVA	10 kEuro

C. Flexibility options

In this subsection the different flexibility options used in this study are presented and summarised in Table II. The purpose of all control methods is to prevent OL and OV.

TABLE II
CONTROL STRATEGIES AND CONTROL DEVICES OF THE FIVE FLEXIBILITY OPTIONS.

Flexibility option	Control device	P-control (business case)	Q-control	Section
cosφ(P)	PV system	maximum feed-in; using feed-in tariff	cosφ(P)-characteristic [23]	III-C1
Q(V)	PV system	maximum feed-in; using feed-in tariff	Q(V)-characteristic [24]	III-C2
RES	PV/RES system	self-consumption; adaptive persistence forecast [25], [26]	-	III-C3
PCR	large BSS	P(f)-characteristic [15]	Q(V)-characteristic (Fig. 3)	III-C2 III-C4
CES	large BSS	like RES; with cumulated profiles	Q(V)-characteristic (Fig. 3)	III-C2 III-C5

1) cosφ(P)-control: The cosφ(P)-control represents the state of the art of the reactive power control by PV systems connected to LV grids and is described in detail in [23]. For most of the installed PV systems in Germany the rated apparent inverter power is smaller than the rated PV-module power. In accordance with the DSO LVN and [8] the ratio of the nominal module power to the inverter nominal power was set to 0.85. In rare occasions, it may happen that an undersized inverter cannot supply the requested active and reactive power in accordance with [23]. If this is the case, the requested reactive power has priority. As this is a technical requirement, it is implemented in the control of all inverters at the market today. As a result the active power is reduced and the revenues of the PV plant owner are reduced accordingly.

As depicted at the characteristic curve shown in Fig. 2 the reactive power is dependant on the the active power that is fed into the grid P_{PV_p}. If the active power exceeds 50 % of the rated inverter apparent power $S_{r,\,inv}$, the power factor is reduced.

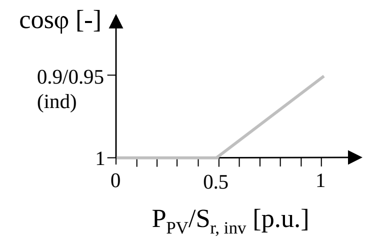

Fig. 2. cosφ(P)-control chacteristics, according to [23].

The minimum power factor depends on the maximum apparent power of the PV inverter [23].

2) Q(V)-control: In the case of the Q(V)-control, the reactive power is adjusted as a function of the voltage at the PCC of the PV system or BSS. Therefore, reactive power is only supplied when it is really needed. In this work, the Q(V)-control is applied to inverters of PV systems without RES and large scale BSS.

The characteristics of the Q(V)-curve for PV inverters installed in Germany are not yet regulated but discussed in a variety of studies [24], [21], [27], [28]. As previous investigations have shown, the stability of this control strategy depends to a large extent on the set control parameters [27], [28]. In this assessment, the stable configuration of [24] is implemented. It is very similar to the characteristic shown in Fig. 3. As in the cosφ(P)-case, the PV system owners may lose part of their income if the PV inverter is not sized accordingly.

To define the points of the Q(V)-characteristic for the large scale BSS, shown for the SPF-prototype in Fig. 3, the maximum voltage limits according to DIN EN 50160 of $\pm$0.1 p.u. were taken as basis [19]. Furthermore, a measurement uncertainty of $\pm$0.01 p.u. was taken into account [21]. As a maximum voltage drop of 0.04 p.u. can be assumed in LV [8], V_4 is set to 1.05 p.u. (1.1 p.u. - 0.01 p.u. - 0.04 p.u.). In order to keep the Q(V)-control stable the same slope (dotted line) as for pure PV systems is used which results in the value of 1.027 p.u for V_3. Since the Q(V)-characteristic is assumed symmetrical to the origin [24], V_2 and V_1 result. A reactive power of 400 kvar is the maximal value, which can be provided simultaneously with a maximal active power of 200 kW by the BSS (4-quadrant operation).

In order to to prevent oscillating interaction of the different Q(V) controllers a first order transfer function (PT1-characteristic), as suggested by [24] is assumed (amplification factor K=1 and a time delay of T=5 s).

3) Residential Storage Systems: Another type of flexibility option to reduce OL and OV is the implementation of RES

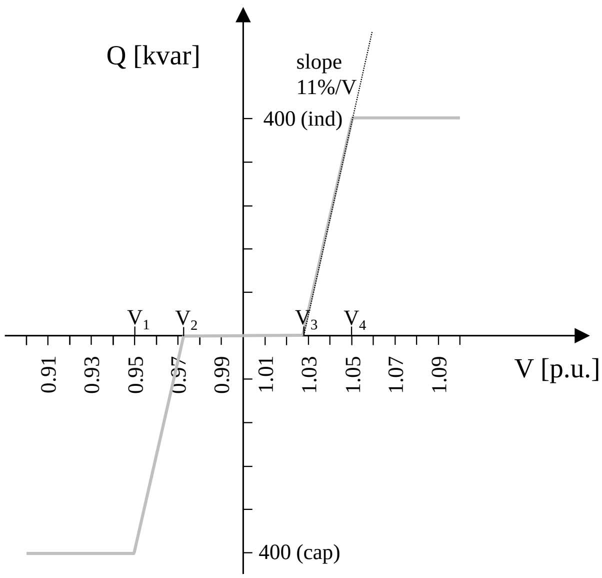

Fig. 3. Q(V)-characteristic used for the large scale BSS reactive power control.

with feed-in limitation. Since 2013, the increase of the self consumption with RES seems to be a viable business model for small PV plants in Germany [29]. To push this storage application the German government launched an incentive program for RES, which is also scientifically monitored [30]. One of the main requirements to take part in the incentive program is to limit the feed-in power of your PV system to 50 %. This feed-in limit is also employed in this study. Preliminary studies by the authors of this paper indicate that the adaptive persistence forecast control strategy may be the most profitable from the storage owner's point of view [14], [13]. This strategy aims on minimising the daily feed-in energy and thus maximising the self-sufficiency and the profit. This is achieved by limiting the feed-in power dynamically, always taking the maximum feed-in boundary into account. The dynamic feed-in limit is ideally set each day based on the forecasts such that the battery is completely charged with the energy that exceeds the dynamic limit [26]. For the load prediction, [25] uses a method that assumes a load profile for the predicted weekday identical to the load profile of the weekday from the previous week. As the PV output has a stronger impact on curtailment losses and self-sufficiency rate than the load forecast, an elaborated method for the PV persistence forecast is used. It is is based on a moving prediction horizon, as well as a on a long term and short term prediction relying on locally measured data of the PV system [25]: 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 strategy secures the best results with regard to the performance indicators (defined in [13]): curtailment loss ratio (CLR), self-consumption ratio (SCR) and self-supply ratio (SSR). SCR is defined as the ratio of the consumed PV production and PV production and SSR as the ratio of consumed PV production and load demand. As storage a lithium-ion battery system with a watt-hour system-round-trip efficiency of 84 % and a depth of discharge between 20% and 90% of its nominal capacity C is assumed [26] (no self-discharge and degradation is taken into account).

Based on [26], [30] for a economical sizing of RES, C should be 1 kWh for a nominal PV power P_{PV_p} of 1 kWp and an annual load consumption LC of 1 MWh. To size the RES, lowercase symbols c, p_{PV_p} and lc are introduced in equation (1) to eliminate the units.

$$c = \frac{C[kWh]}{kWh};\ p_{PV} = \frac{P_{PV_p}[kW_p]}{kW_p};\ lc = \frac{LC[MWh]}{MWh} \quad (1)$$

The sizing rule of [26], [30] can now be written as follows:

$$c : p_{PV} : lc = 1 : 1 : 1 \quad (2)$$

As $p_{PV} \neq lc$ for most of the PV systems in the pilot village the storage capacity is sized to match the lower value. This is shown in equation (2) where c depends on p_{PV_p} and lc. C is limited to 30 kWh for RES.

$$c = p_{PV},\ if\ p_{PV} \leq lc \quad and \quad c = lc,\ if\ lc \leq p_{PV} \quad (3)$$

4) Pooled Large Scale BSS for Primary Control Reserve: In this section the focus lies on large scale BSS providing PCR, defined in [31]. The PCR is automatically activated after detecting a frequency deviation from 50 Hz according to the curve depicted in (Fig. 4). It has the aim to balance the consumed and generated power in the system so that the system frequency stabilises. The applied system supportive PCR operation strategy and simulation model is presented and validated in [15]. For modelling the operation strategy of the PCR, it is assumed that the BSS wins every auction and provides PCR the whole year. The frequency time series are provided by the TSO Swissgrid AG.

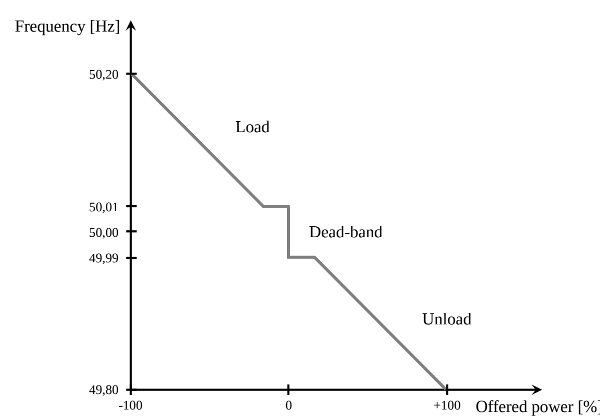

Fig. 4. Relation between frequency deviation and provided primary control reserve

In the SPF-project the BSS is connected to the LV busbar of a MV/LV-transformer. It provides PCR according to a P(f)-function, depicted in Fig. 4, and reactive power according to a Q(V)-function, as shown in Fig. 3. The active power for the PCR is calculated by applying the P(f)-characteristic as an input of the static load flow calculation added to it as a profile, whereas the voltage dependent reactive power values are calculated for every time step according the Q(V)-function.

Within the village described in section II, large BSS are connected to the LV grids. However, the BSS in the Smart-PowerFlow project has a rated power of 200 kW and can lead to OL in some MV/LV-transformers. Therefore, the BSS are sized so that the hosting capacity of the pilot region is not reduced compared to the reference scenario, in which no flexibility options are applied (a perfect foresight is assumed).

5) Community Electricity Storages: The VRFB-prototype battery model of the SPF-project is also used to simulate a CES operation mode. This mode has not been implemented in a field test. As for the PCR option, the BSS is connected to the LV-busbar of the MV/LV transformer and the same reactive power control applies. Instead of providing PCR, the active power of the BSS is used in this case to maximise self-consumption with the same operation strategy as the RES. Although the incentives of [30] are only granted for RES (30 kWh limit), the 50 % limit is used also for CES to assure a better comparison. For every CES, the profiles of the generators and loads are summed. The operation strategy applies these accumulated profiles. The resulting charging or discharging power is calculated for every 1-min time-step. The depth of discharge of the VRFB is set between 1 % and 99 % of its nominal capacity of 400 kWh. The operation strategy and battery model is explained in detail in [15].

It is assumed that the sizing rule of RES (see equation 2) applies also to CES, with the exception that the capacity is of the BSS is fixed to 400 kWh. Since the BSS is connected to the LV-side of the MV/LV-transformer, all the loads and PV systems of the same LV grid were assigned to one CES if possible, otherwise the loads of nearby LV grids were assigned. This leads to a non-optimal sizing of the loads and PV systems, but increases the hosting capacity of the LV grids by preventing OL of the MV/LV-transformers. To avoid OL due to the reactive power flow induced by the Q(V)-control, the CES are installed at LV grids with MV/LV-transformers with at least 250 kVA rated apparent power.

IV. Results and Discussion

Firstly, the resulting sizing, allocation and performance of the three storage options are presented and discussed. Secondly, the impact on the grid of the various flexibility options are compared under technical and economic criteria.

A. Sizing, Allocation and Performance of the Storage Options

1) Residential Storage Systems: When the sizing rule presented in equation 3 is applied to the reference scenario only 31 % of the RES of the pilot region lie within the economical favourable range of p_{PV}:lc of 0.5:2. As curtailment losses depend on the sizing of the RES and the c:p_{PV}:lc-ratio varies greatly, the impact on performance indicators is severe, as shown in Table III. The performance indicators were calculated using a yearly simulation in 1-min steps. It can be seen that the bigger the difference ratio between lc and PV size, the poorer the performance of the storage system. The average household curtailment loss in the pilot village amounts to 6.5 %. The average RES size is 5.1 kWh and 92 % of the RES are below 10 kWh. However, as large PV systems with a non-optimal p_{PV}:lc-ratio curtail large amounts of energy, the total losses for the village rises to 9.3 %.

TABLE III
Performance indicators for different RES system sizings.

c:p_{PV}:lc-ratio	SCR	SSR	CLR
1:100:1	1%	87%	11%
1:1:100	100%	13%	0%
1:1:1	51%	73%	3%

2) System Supportive Pooled Battery Storage System for PCR: The sizing and allocation of the BSS providing PCR results form applying the methodology described in section III-C. As for the VRFB-prototype the ratio of rated reactive power to rated active power (Q2P) and the ratio of rated capacity to rated active power (E2P) is kept 2:1 for all BSS within the pool. Therefore, in Table IV, only the installed rated (index) power $P_{bat,r}$ of each BSS for every low voltage grid are listed. In T2, T7, T8 and T9 (name of the corresponding LV-grid and transformer) no BSS are installed, as this would have reduced the hosting capacity compared to the reference scenario, and perfect foresight is applied which only allows an increase of the hosting capacity.

TABLE IV
Installed rated power $P_{BAT,R}$ of each BSS for every LV grid.

LV grid	T1	T3	T4	T5	T6	T10	T11	T12
$P_{bat,r}$ [kW]	400	100	50	100	100	100	300	50

3) Grid Supportive Community Electricity Storages: In the status quo there are 2.1 MW of PV power installed in the pilot village. As the sizing rule of equation 2 has been applied, only the geographically closest loads with a cumulated LC of 2.3 GWh, were combined to 5 separate CES systems with a C of 400 kWh. To comply with the sizing rule, by installing more and more PV systems, more CES can be installed, too. For every 400 kW of additional cumulated PV power a new CES is added. In total 8 BSS operated as CES are installed in the pilot village until 2025.

Performance indicators and allocation: The performance indicators SCR and SSR and the allocation for all 8 CES are listed in Table V. The indicators were calculated with (index PV) and without storage (index BSS) in order to evaluate the influence of the BSS operating as a CES. It can be seen that the BSS increases the SCR and the SSR. The first row of the table shows the ratio of the PV systems connected to the CES P_{PV} in kW_p and the cumulated LC in MWh, respectively.

The influence of the dimensioning of the load and PV can be shown by the example of CES 5. In this case, there is significantly more load connected to this CES than to the other storages, leading to the smallest increase of the self-consumption rate from 55 % without CES (SCR_{PV}), to 60 % with CES (SCR_{BSS}). The oversized CES 8 on the other hand,

TABLE V
ALLOCATION, SIZING AND CALCULATED PERFORMANCE INDICATORS OF THE CES (400 KWH) FOR THE YEAR 2025.

	CES 1	CES 2	CES 3	CES 4	CES 5	CES 6	CES 7	CES 8
LV grid	T1	T6	T9	T10	T11	T4	T7	T12
p_{PV}:c:lc	1.2:1:1	1.1:1:1.1	0.9:1:0.9	0.9:1:1.1	1:1:1.6	1:1:1.4	1.1:1:1.3	0.7:1:0.6
SCR_{PV}[%]	33	41	34	37	55	43	46	30
SCR_{BSS} [%]	51	59	52	54	69	60	63	47
SSR_{PV} [%]	45	44	45	43	43	41	41	51
SSR_{BSS} [%]	67	62	68	63	54	56	56	79
CLR_{BSS} [%]	0.9	0.8	0.8	0.7	0.5	0.6	0.7	0.8

results in the highest self-supply ratio with CES SSR_{BSS} of 79 %. The curtailment loss ratio CLR_{BSS} for all CES lies under the negligible level of less than 1 %. This is a factor 3 to 7 smaller then the curtailment losses of the same operation strategy applied to one optimal sized residential PV-storage system, if compared with [14] and Table V and a factor 9 smaller for the whole village. The negligible curtailment losses and the reduction potential of CES matches with the results of a similar study [32].

B. Technical Assessment

To compare the flexibility options technically, the hosting capacity for every flexibility option was calculated. To calculate the hosting capacity of each of the five flexibility options, the status quo of the grid was expanded with PV systems according to section II until the hosting capacity of each LV grid was reached. The sum of status quo of the PV systems (2.1 MW) and additional installations (1.1 MW) represents the hosting capacity of 3.3 MW for PV systems in the village without flexibility and was used as a reference scenario. The increase of the maximum hosting capacity with respect to this reference scenario is shown in Fig.5.

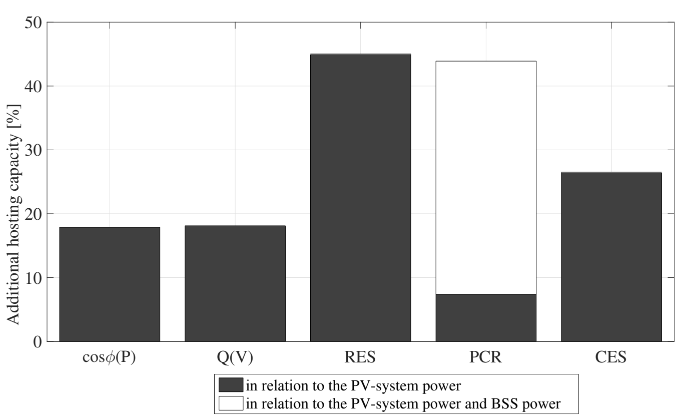

Fig. 5. Additional hosting capacity compared to the reference scenario (3.3 MW).

As depicted in Fig. 5, for all flexibility options additional PV systems can be integrated. Thus, the hosting capacity can be increased for all flexibility options. Differing from the additional maximum hosting capacity shown in Fig. 5 , the increase of the additional PV system power of the different options are calculated as ratio of the additional power of the reference case (1.1 MW) and the additional power of the option. The additional PV system power is increased by 52 % (1,7 MW) for the cosφ(P) option, by 53 % (1.7 MW) for the Q(V) option, by 129 % (2.6 MW) for the RES option, by 21 % (1.4 MW) for the PCR option and by 78 % (2.0 MW) for CES option.

The PCR option represents a special case: In spite of adding additional generator capacity to the grid (from the DSO's perspective) the hosting capacity is increased due to the grid supportive behaviour of the Q(V)-control. For this option the hosting capacity for PV systems can be increased by 7 % (black bar) or 44 %, if the additional BSS systems are considered as additional generators (white bar). In the RES and CES scenarios the nominal power of the RES/CES cannot be considered as additional generators connected to the system, since these systems only have a time shifting purpose. As these systems are designed to increase self-consumption, they do not feed into the grid at all (RES) or at least not at the same time as the PV systems (CES).

In the different LV grids (see Fig. 1), the additionally installed PV power varies greatly depending on the grid topology. For the grids T1, T5, T11 and T12, the full PV potential can be connected to the grids for all scenarios, because the maximum hosting capacity is not reached in any of these grids.

In the reference scenario the hosting capacity is limited mainly by OV.

In the case of the two reactive power control scenarios cosφ(P) and Q(V), more PV systems can be connected to the grids T2, T3, T6, T7, T9 and T10, as in the reference scenario in which OV limits the hosting capacity. The reactive power control flexibility options can solve the OV issues such that further PV systems can be connected until the OL threshold is reached. The increase in hosting capacity of the cosφ(P)- and of the Q(V)-option are close to the reported values of 20 %-40 % for rural grids [33] and the median of additional PV system power of approx. 60-80 % calculated by [21].

In the RES-option the hosting capacity is limited mainly by OV. In the RES-case this issue is addressed successfully by limiting the feed-in power by applying a 50 % feed-in limit to the operation strategy. In contrast to the two previous flexibility options, the RES option limits the feed-in power. As a result, OL and OV occurs at higher penetration rates and thus more PV systems can be connected to the grids T2, T3, T6, T7 and T9 compared to all other options.

The main difference from the scenario in which large scale BSS provide system supportive PCR to the other flexibility options, is that in this case the BSS represent additional generators connected to the grid. This is due to worst case

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assumptions applied in traditional grid planning in which the PV systems and the BSS act as generators providing their maximum power. Nevertheless, this flexibility options increases the hosting capacity for the grids T2, T6, T7, T9 and T10. If the rated power of the BSS in the PCR options are considered as additional generators this option is almost as effective (1 % less additional maximum hosting capacity) as the one in which RES are employed.

The option with the second highest increase of PV systems is the CES option, even if in T2, T3, T5 and T8 there are no CES installed and the hosting capacity of these grids cannot be increased.

The analysis of the LV grids shows that the reactive power control options (Q(V) for CES, PCR and PV systems, cosφ(P) for PV systems) can relieve LV grids with long feeders, OV issues and low capacity utilisation of the MV/ LV transformers, since in these cases the hosting capacity of the LV grid can be increase until OL occurs in the MV/ LV transformers.

C. Economic Assessment

In this section the economic aspects of traditional grid expansion (economic reference case without flexibility) versus the application of flexibility options are presented. As described in section III-B for the economic assessment a PV-expansion pathway based on the aims of the Bavarian government and the resultant grid reinforcement are considered from 2013 until 2025. The net present value method, with the assumptions presented in section III, is applied to compare the different flexibility options. For the calculation of the net present value, with a evaluation period from 2013 until 2050, it is assumed that the grid will remain at the status of the year 2025 (no additional PV, no further grid expansion).

In Fig. 6 the costs that have to be borne by the DSO and by the BSS or RES owner are shown.

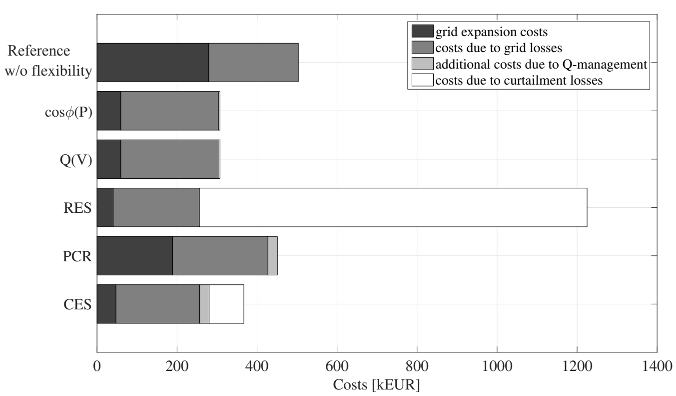

Fig. 6. Total costs borne by the DSO and by the BSS or RES owner for all scenarios.

The costs that concern the DSO are: the grid expansion costs, costs to due grid losses and additional costs due to Q-management. The grid expansion costs are net present values of the grid assets minus the residual values of the assets in the year 2050. The operation expenditures consist of the costs due to grid losses and the costs connected to the Q-control of the large scale BSS for the whole evaluation period of 2013 until 2050. As shown in Fig. 6 and in Table VI, all flexibility options result in lower grid reinforcement and total costs compared to the reference scenario without flexibility option.

TABLE VI
RELATIVE COSTS OF GRID EXPANSION AND GRID LOSSES FOR THE DSO FROM 2013 UNTIL 2050 FOR THE OF THE FLEXILITY OPTIONS IN RELATION TO THE REFERENCE WITHOUT FLEXIBILITY.

	grid expansion costs	costs due to grid losses	total costs (total costs incl. Q-management)
Reference	100%	100%	100%
cosφ(P)	21%	109%	60%
Q(V)	21%	110%	61%
RES	15%	96%	51%
PCR	68%	107%	85% (90%)
CES	17%	94%	51% (51%)

The costs for the grid losses could only be lowered by 8 kEUR (4 %) for RES option and by 14 kEUR (6 %) for the CES option. The other flexibility options result in higher grid losses: 15 kEUR (7 %) for PCR, 22 kEUR (9 %) cosφ(P) and 23 kEUR (10 %) for Q(V). The higher grid losses are caused by the increase in thermal losses induced by the additional reactive power in the grid caused by the reactive power control of these flexibility options. A much higher influence of the flexibility options can be seen in the grid reinforcement costs: the RES-option may save up to 239 kEUR (85 %), the CES-option 232 kEUR (83 %), the options cosφ(P) and Q(V) 220 kEUR (79 %) and the PCR-option 30 kEUR (32 %) of the grid expansion costs until 2025. Thus, all options, except the PCR-option, have a higher potential to reduce grid expansion costs as the 58 % reported by [34] for static feed-in management, in which the active power of the PV system is limited to 60 %, which from the DSO's perpective is very similar to the RES option. The comparison with [34], shows also that the results presented in this study are consistent, as the RES-option (50 % feed-in limit), shows higher saving potential, than the static feed-in (60 % feed-in limit) management option of [34].

As presented in the introduction, the (main) hypothesis of this paper is that, from a DSO point of view, the additional costs that have to be paid to a third party BSS operator, which provides voltage control additionally to its main business cases (PCR and CES option) can be lower, than the costs of avoided grid expansion. Thus, this hypothesis is analysed hereafter.

To analyse whether the DSO should apply the BSS with the only purpose of avoiding grid expansion cost, the avoided grid expansion cost (grid expansion costs of reference case minus the grid expansion cost of considered flexibility options, taking into account the imputed residual value of grid assets) are set into relation to the CAPEX of the installed BSS. Assuming the costs of [35] for VRFB and alternatively NMC Li-BSS, the total CAPEX of for the two options are 2.3 MEUR (PCR) and 3.1 MEUR (CES) for VRFB and 1.1 MEUR (PCR) and 1.6 MEUR (CES) for Li-BSS. Set into relation with the avoided grid expansion costs these avoided costs are only 3 % (PCR) and 10 % (CES) of the CAPEX of these BSS. If Li-BSS are applied, the avoided costs are 6 % (PCR) and 20 % (CES), due to the lower CAPEX for this technology. Thus, it is clear that it is unprofitable for this given case that a DSO would invest in BSS only to operate them as volt/var device, as it is in

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PCR option. But is is also not profitable for the DSO to invest in the BSS for peak shaving and combining it with the reactive power control (CES option). This, strengthens the assumption that the BSS CAPEX has to be burdened by a third party BSS operator and not the DSO. This assumed BSS operator peruses a viable business case (PCR or self-consumption maximisation with the CES) and provides voltage control as an additional service to the DSO. Assuming that this is the case and for the two presented business cases, the additional costs of the reactive power provision are less than 1 % of the revenues, if the VRFB presented in this work is applied. The detailed techno-economic assessment of these business cases, from the BSS operator's view, are presented in [15]. It is assumed that the large scale BSS operator is reimbursed for the additional costs caused by the Q-management. The total cost burden for the Q-management is 24 kEUR for PCR and the CES option. The second additional costs that has to be burdened by the DSO are the additional grid losses of 15 kEUR for PCR and CES, as discussed before.

To show that the hypothesis is true, the sum of the costs to due grid losses and additional costs due to Q-management should be smaller than the avoided grid expansion costs. This is the case as for the PCR option the DSO can save 52 kEUR and for the CES option 193 kEUR (mainly attributed to the peak shaving and the resulting curtailment losses).Thus, in total the DSO can save 10 % in case of the PCR option and 49 % for the CES option of the total costs compared to the reference scenario (see values in brackets in the third column of Table VI). It can be concluded that for this pilot grid the DSO would have to reimburse 43 % of the avoided grid expansion costs to the BSS operator in the PCR option, whereas in the CES option it would only be 17 %. Finally, it could be shown that market driven storage applications like PCR or CES can reduce grid expansion costs, if the BSS is sized and allocated properly and combined with a reactive power control strategy.

In a more holistic cost assessment in addition to the costs of the DSO the curtailment losses by the BSS or RES have to be considered, too. These costs are not reimbursed and are borne by the battery owners. In the cosφ(P) and Q(V)-option these costs apply only in the case when the active power has to be reduced to provide the reactive power requested. Even if these costs are very low for these two options, it can be shown that the Q(V)-control is able to reduce the curtailment losses by 50% from 4 kEUR to 2 kEUR. Furthermore, the RES-option which is the most profitable solution from the DSO's point of view appears to be the least profitable if the curtailment losses are also taken into account. This is due to the 50 % feed-in limit which under the non-optimal storage sizing (see section III-C) for already existing PV systems leads to total costs that exceed the costs of the reference scenario by more than 100 %. Finally, the CES-option shows a high cost saving potential compared to RES by sharing large scale BSS to maximise self-consumption. This is especially true, if non optimal sizing of the RES is applied. For the pilot village the costs due to curtailment losses can be reduced by 91 %, turning the CES-option into the most profitable one, if storage systems are integrated into a existing grid to prevent future grid expansion costs.

V. Conclusion

In this paper five flexibility options are analysed as an alternative to PV induced traditional grid expansion for a specific pilot region. The options are: two reactive power control strategies with PV inverters, one residential and two large scale BSS applications. The flexibility options are assessed from a technological and an economical point of view.

The main finding of the technological evaluation is that for all flexibility options the hosting capacity for PV systems can be increased in the distribution grid of the pilot region compared to the reference case which represents traditional grid expansion. The most effective flexibility options in descending order are: RES, CES, Q(V), cosφ(P) and PCR. However, if in the case of PCR the additional BSS are considered as generators, PCR becomes the second most effective option.

The economic assessment shows that from a DSO's point of view all flexibility options are preferable alternatives to traditional grid expansion for the analysed pilot region and PV-expansion pathway. From all scenarios the RES-option shows the highest cost saving potential. The cost saving ranking order is the same as the technical ranking. This reflects the capability of the flexibility option to increase the hosting capacity and therefore reduce grid expansion costs. It could be shown that the reduction of the grid expansion costs has the most impact on the DSOs' costs as all flexibility options lead to similar grid operation costs.

In conclusion, all analysed flexibility options are capable of reducing the grid expansion costs compared to a scenario with only traditional grid expansion. The main novelty of this paper is that could be shown and quantified that BSS, owned by a third party, can pursuit a viable business model using an active power operation-based strategy (PCR or self-consumption) and additionally to this a reactive power control can be applied to reduce future grid expansion costs. The additional costs for reactive power control the are much smaller than traditional grid expansion costs needed otherwise.

Finally, DSOs are therefore encouraged to consider the integration of additional PV and battery storage systems with the applied operation strategy as part of the solution to reduce the necessity for grid reinforcements compared to traditional approaches. This is due to the cost reduction potential, if a system/ grid supportive behaviour is applied which largely exceeds the extra costs. Future studies should calculate the economic and technical value of the system/ grid supportive behaviour of the combined flexibility options, similar to the approach of [36] from a grid operator's perspective in order to mitigate further grid expansion in grids with high shares of renewable energies and also include a probabilistic approach.

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