Optimal Generation Dispatch of Distributed Generators Considering Fair Contribution to Grid Voltage Control

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Abstract

This paper investigates voltage control and generation dispatch of distributed generators (DGs) and how the operation of installed DGs can be optimized in distribution systems. A novel online generation dispatch algorithm for DGs is proposed in this work. This algorithm optimizes the contribution of individual DG units for grid voltage control in terms of costs. The technical advantages of the presented approach are evaluated by comparing the simulation results with various static and local dispatch control strategies, which can be considered currently as state-of-the-art according to technical standards and recent research. Simulation results indicate that the proposed method decreases the total cost for DG, improves the quality of voltage profiles and guarantees for each DG unit the opportunity to provide a fair amount of ancillary service to the grid. Additionally, through a performance test on a real time simulation platform it is concluded that the presented approach is also suitable for large grids in real time operation.

Keywords: Distributed generation, generation dispatch, real time simulation, volt/var control, linear programming.

1. Introduction

Due to economic incentives and technological maturity, installations of small and medium sized renewable energy generators have rapidly increased since years. Especially in the rural areas, voltage rise, which is one of the major impacts of DGs, have been challenging conventional planning and operation of distribution systems.

A range of options have been suggested for distribution system operators (DSO) to mitigate critical voltage rise. Measures for grid reinforcement are normally combined with considerable high costs. Alternatively, new regulatory requirements on DGs are introduced, e.g. [1] and [2]. According to these grid codes, although equally valid for all systems, the operational set-point of DGs is always configured very conservatively and thus inefficient considering some critical situations which rarely occur, e.g. overvoltage and overloading. In recent studies, local autonomous power control (APC) and voltage droop mechanisms present their technical effectiveness in mitigating large voltage deviations [3], [4]. By means of reactive power provisioning and active power curtailment, DGs can actively contribute to grid voltage regulation and increasing hosting capacity of distribution grids. However, applying these APC or voltage droop control strategies, some PV systems, which are located at the end of feeders, have to provide the ancillary service more often than other systems installed at the beginning of feeders. These kind of local control strategies cause therefore an unfair distribution of costs for DG owners due to the involved losses associated with grid voltage support. This situation presents new challenges for improving economy and security of power system operation with consideration of customers' costs.

In this study, we present a new central generation dispatch algorithm for voltage control in distribution systems. It minimizes the total loss for all DG units by optimizing their output set-points; at the same time, it guarantees that all DGs bare the same cost of ancillary service to the grid with respect to their installed capacity. The proposed method is tested with two case studies under high photovoltaic (PV) penetration conditions. Through comparison with the

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standard regulatory measures and the local control mechanism, the technical and economical effectiveness of the new control algorithm is validated. In addition, the feasibility of this algorithm for online applications is also proved by implementing the algorithm on a large grid model on a real time simulation platform.

Main contributions of this work are:

- This work emphasizes the cost of DG owners for provision of voltage support to the grid. It differs from previous studies, which normally start from the point view of a DSO and aim at operating the whole distribution system optimally with respect to minimization of grid losses and improving voltage profiles. In this work, we assume that the voltage problem caused by power feed-in is also an objective by optimal dispatch of DGs. This optimum denotes the minimum of total cost by all DG owners in the whole system.

- Furthermore, we focus on a fair distribution of costs considering the size (installed capacity) and the location of DGs in the grid. Based on the proposed dispatch algorithm, the same specific costs for all DGs can be achieved without significantly increasing the total costs. Its effectiveness is evaluated on a real LV grid model with measured PV profiles for the investigated grid area. Also, both the offline and real time implementations of this strategy together with the grid simulation model prove the effectiveness and the applicability of our approach.

This paper is outlined as follows. In Section II, a detailed literature review on related work is given. Section III describes the proposed dispatch algorithm, and in Section IV, assumptions and parametrization of the simulation are presented. In Section V, different control strategies are evaluated by comparing the simulation results. Finally, a short conclusion and a discussion about possible future work is given in Section VI.

2. Related Work

Voltage control and reactive power dispatch are originally considered as a power system planning problem. They are typically formulated as reactive power planning (RPP) problems in literature mainly at the transmission system level. These publications have the common objective to optimize the voltage profile by control of the reactive power flow. Active power has not been treated as a control subject, because generation is determined by consumption, which is normally not controllable by utilities.

A comprehensive overview on RPP is provided in [5]. According to this work, strategies for solving this type of optimization problem are differentiated by their definition of objective function, definition of constrains and applied mathematical methods. Traditionally, it is characterized as an optimal power flow problem with the typical objective of grid loss minimization [6], [7], [8], [9], mitigating voltage fluctuations [6], [8], [9] and/or minimizing the total demand of reactive power compensation [10]. Depending on the formulation of the objective function and the constrains, these problems are solved by linear or non-linear programming techniques.

With the presence of DG at distribution level, new tendencies can be identified among recent publications. First, the conventional, worst-case based planning solutions will not efficiently solve the voltage control challenge in distribution systems due to the highly fluctuating nature of renewable energy sources. Thus, the voltage problem needs to be solved also online by grid operation. Some work present online volt/var control (VVC) strategies for voltage control [10], [11]. The optimization goal is formulated thereby similar as for RPP. Multi-objective optimization (MO) and heuristic methods for voltage control can be found in [6], [8].

Second, DGs can provide support for control of grid voltages by means of reactive power provision, as it is also suggested by the conventional reactive power dispatch topics. This method is investigated by publications [3], [4], [10] and [12]. Besides, active power reduction is also considered as a second option by [4], [9] and [13]. To sum up, new solutions should be able to equally address both of the possibilities offered by DG in order to achieve the system optimum.

Last, provision of ancillary service also means loss of profit for DG owners. This subject is studied as the reactive power cost allocation (RPA) problem. In the RPA formulation, a special view on individual contribution of DG units to total voltage support is analyzed. By investigating the Jacobian matrix [14] or the modified Y-bus matrix [15], a sensitivity matrix indicating voltage changes at all nodes according to the change of reactive power set-points of individual DG units can be constructed. With help of this sensitivity matrix, costs of reactive power provision can be determined individually for each DG unit. The investigations help to understand the complexity of the generation dispatch problem in distribution systems.

This work aims to minimize the total costs for DG units considering the losses caused by participation in grid voltage support, while ensuring voltage regulation and operational limits of DGs. By utilizing the Jacobian matrix for voltage estimation, the whole problem can be solved linearly. In addition, the proposed algorithm is a joint optimization of active and reactive power set-points with consideration of a fair distribution of individual costs for each DG. As commonly required by central control mechanisms, it is assumed that necessary measurement devices and a communication infrastructure exists in the power system under consideration.

3. Problem formulation

Based on measurements of bus voltage and the maximal current generation potential of each DG unit, the proposed central generation dispatch algorithm optimizes the active and reactive power set-points of generation units at each time interval. In the following, the objective function and the associated boundary conditions are first presented. The work flow of this approach is demonstrated in the second part of this section.

3.1. Cost Specification of Generation Dispatch

In order to mitigate overvoltages in the grid, generation units are requested to absorb reactive power and/or reduce their active power feed-in. Both of these two options cause loss of profit for DG owners. For feed-in energy, DG owners are paid according to either a fixed tariff or a flexible retail price related to spot market. This price is applied for calculating the cost of DG owners. For reactive power provision, DG owners may be compensated by a negotiated price with the DSO. As there is currently no reactive power market existing in Germany, a price charged by a DSO for customers with low power factor is considered as a reference [16]. Therefore, costs of generation dispatch for each DG unit can be specified by combining the cost of reduced feed-in energy and the cost for reactive power provision, which are determined according to Eq. 1:

$$c_i = Price_{EP} \cdot \Delta P_i \cdot dt + Price_{EQ} \cdot \Delta Q_i \cdot dt. \tag{1}$$

c_i stands for total costs of one PV system due to the adjustment of both active and reactive power set-points. $Price_{EP}$ and $Price_{EP}$ are the specific prices for active and reactive energy in €/kWh and €/kvarh, respectively. ΔP_i and ΔQ_i denote the reduced active power and extra reactive power output of DG comparing to only feed-in of active power. dt equals to the time interval of dispatch control.

3.2. Objective Function

The main objective of this central dispatch algorithm aims to minimize the total costs of all DG units, due to their participation in voltage support, by determining their optimal generation set-points. The overall objective function can be expressed as follows:

$$\min f = \sum_{i=1}^{n} c_i, \tag{2}$$

where i is the index over all DGs. It is subject to:

$$0 \leqslant \Delta P_i \leqslant (1 - p_{lim,i}) \cdot P_{max,i}, \tag{3}$$

$$0 \leqslant \Delta Q_i \leqslant P_{max,i} \cdot \sin \varphi_{lim,i}, \tag{4}$$

$$\frac{-\Delta P_i}{(\cos \varphi_{lim,i} - 1) \cdot P_{max,i}} \leqslant \frac{\Delta Q_i}{P_{max,i} \cdot \sin \varphi_{lim,i}}, \tag{5}$$

$$u_i = u_{0,i} + \Delta u_i \leqslant u_{max,i}. \tag{6}$$

where

$$\begin{bmatrix} \Delta \delta_i \\ \Delta u_i \end{bmatrix} = J^{-1} \cdot \begin{bmatrix} \Delta P_i \\ \Delta Q_i \end{bmatrix} = \begin{bmatrix} \frac{d\delta}{dP} & \frac{d\delta}{dQ} \\ \frac{du}{dP} & \frac{du}{dQ} \end{bmatrix} \cdot \begin{bmatrix} \Delta P_i \\ \Delta Q_i \end{bmatrix}. \tag{7}$$

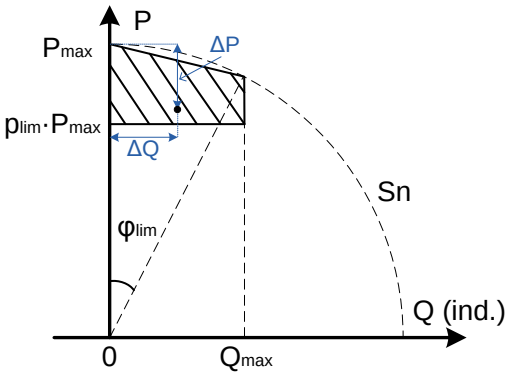


Figure 1: Feasible region of DG's P, Q setpoints, marked as shaded area

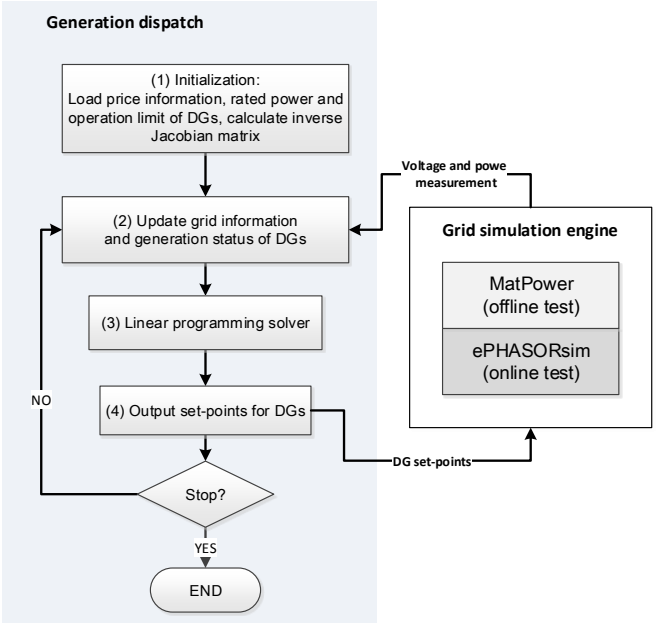


Figure 2: Flow chart of proposed algorithm and communication with grid simulation

Possible operation ranges of active and reactive power are defined in Eq. 3 and Eq. 4. Herein, change of active power for the ith DG unit (ΔP_i) is determined by its maximal potential output at current time step $P_{max,i}$ and the maximal permissible power reduction $p_{lim,i}$. For reactive power, it can be adjusted within the range from zero to a maximal value, which corresponds to a minimal power factor $\cos\varphi_{lim,i}$ and the generation potential $P_{max,i}$, which is one input information required by the algorithm. Eq. 5 is a linear approximation of the quadratic relationship between active and reactive power. These three equations define the feasible region of P, Q set-points, which is illustrated as a shaded area in Fig. 1. In addition, the voltage magnitude at all points of common coupling (PCC) should remain below certain permissible limit $u_{max,i}$. As written in Eq. 6, node voltage is estimated by the sum of measurement values $u_{0,i}$ (before dispatch control) and potential voltage deviation Δu_i by changing the generation set-points (ΔP_i and ΔQ_i). According to the power flow equation, the voltage deviation can be linearly estimated by the deviation of active and reactive power of all PQ nodes. This is represented in Eq. 7. It should be noticed that only the lower half of inverse Jacobian matrix is required for the estimation of voltage magnitude.

A further boundary condition, denoted as fairness condition in this work, is expressed in Eq. 8. It aims to equalize the dispatch associated costs by each DG with respect to its installed capacity (S_{n_i}). In order to achieve the same cost by each DG unit, the difference of specific costs is therefore limited within a certain tolerance band, defined as ϵ.

$$\left|\frac{1}{S_{n_{sum}}}\cdot\begin{bmatrix} S_{n_{sum}}-S_{n_1} & -S_{n_1} & \cdots & -S_{n_1} \\ -S_{n_2} & S_{n_{sum}}-S_{n_2} & \cdots & -S_{n_2} \\ \vdots & \vdots & \ddots & \vdots \\ -S_{n_n} & -S_{n_n} & \cdots & S_{n_{sum}}-S_{n_n} \end{bmatrix}\cdot\begin{bmatrix} c_1 \\ c_2 \\ \vdots \\ c_n \end{bmatrix}\right| \leqslant \begin{bmatrix} \epsilon \\ \epsilon \\ \vdots \\ \epsilon \end{bmatrix}. \tag{8}$$

where $S_{n_{sum}} = \sum_{i=1}^{n} S_{n_i}$. It stands for the sum of installed capacity of all DG units in the grid.

3.3. Work Flow and Implementation of Generation Dispatch Algorithm

Considering the formulation of objective function and boundary conditions, this objective can be solved as a linear programming (LP) problem. A general work flow of the dispatch algorithm is illustrated in the left half of Fig. 2. Details of each step are further explained as follows.

(1) *Initialization of algorithm*

At the initial step, price information, either constant value or dynamic profile, is loaded by the the dispatch algorithm. Rated power and parameters related to operation limit of individual DG units are also defined in this

step. Finally, the inverse Jacobian matrix is calculated based on power flow model of the grid, which is utilized for estimation of bus voltages.

(2) *Update input variables*

At beginning of each optimization step, measurement values of grid voltage and maximal output power of each DG are generated by the the grid simulation, which is forwarded to the dispatch algorithm as input data. Based on this information, boundary conditions of the problem are updated.

(3) *Linear programming solver*

This optimization problem is solved using an LP algorithm, which is provided by the Matlab Optimization Toolbox. The algorithm terminates, if either the optimum set-points of DG units are found or the maximum number of iterations is reached.

(4) *Output set-points*

The determined operation set-points obtained by the generation dispatch algorithm are transferred to the grid simulation. A new grid status is calculated with the updated set-points of DG.

4. Assumptions for simulation and voltage control strategies

4.1. General Assumptions

Assumptions concerning energy price and operation limits are derived from current regulatory requirements and technical standards in Germany.

(1) *Price information*

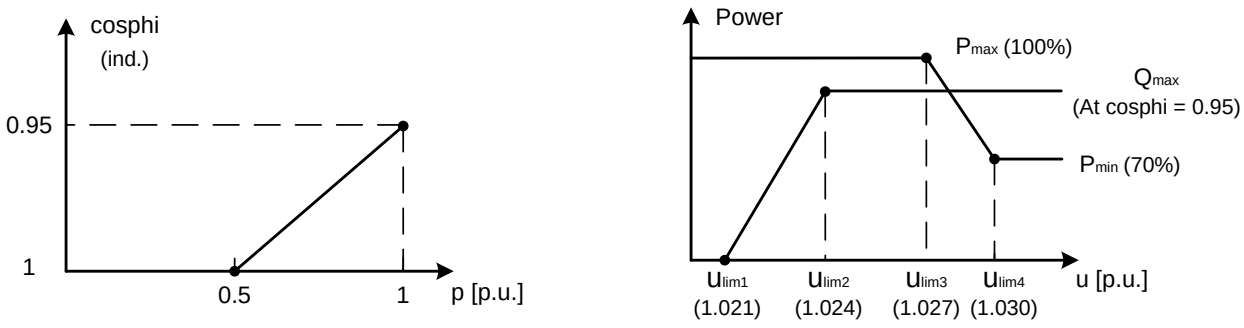
Cost for active power reduction are calculated according to the feed-in tariff of 0.1563 €/kWh (May 2013), according to German Renewable Energy Sources Act [17]. For reactive power compensation, a fixed price of 0.0153 €/kvarh is defined in this study according to [16].

(2) *Operational limit of DG*

According to the current German grid code for LV grid [2], the additional voltage rise at any PCC, caused by the power feed-in of DG, is not allowed to exceed 3% of the voltage without generation. For MV level, [1] specifies 2% as the maximum permissible voltage change caused by DGs. These limits are considered as voltage limit by dispatch strategies in this work. Since 2012, a fixed limitation (70%) of the active power feed-in at PCC is an option in Germany for new installed PV systems with an installed capacity less than 30 kWp [17]. Accordingly, a maximum active power curtailment of 30% is considered as operation limit for active power reduction in this study. Finally, limits for reactive power provision are given by [2], i.e. DG with an installed capacity less than 10 kWp should able to operate with a minimal power factor of 0.95. All PV systems investigated in this paper lie within this range.

4.2. Alternative Strategies for Power Dispatch of DG

The central generation dispatch algorithm and several alternatives, presented in Tab. 1, are implemented in order to benchmark the proposed method. The strategy **UPF** can be regarded as a reference scenario, where all DGs are purely feed in active power with the maximum generation capacity, in order to specify the costs associated with other strategies. Strategy **CPF** and **PCurt** are static settings with fixed parameter. They are refered to current requirement according to standards. Hereby, DGs are either operated at a constant power factor (**CPF**) or with a constant share of feed in curtailment (**PCurt**). For strategy **PFCh** and **VDp**, output power of DG is locally determined by a predefined control characteristics. In addition, the strategy **PFCh** is also recommended by the standard [2] as an alternative to **CPF**. Although it is not yet included by the standard, the strategy **VDp** has already been studied by several previous works, such as [4]. The proposed central dispatch algorithm is applied as strategy **CFD** to emphasize a fair cost distribution among all DGs. Strategy **CD** is also implemented without the fairness constraints. It is expected that the strategy **CD** achieves the minimal cost as it is able to determine the global optimum. The proposed strategy **CFD** can



(a) Static power factor characteristics

(b) Local voltage droop control

Figure 3: Local generation dispatch Strategy (PFCh and VDp)

Table 1: Investigated strategies for voltage control and generation dispatch

Index	Strategy	Explanation
UPF	Unity power factor	A reference scenario with unity power factor for all DG units.
CPF	Constant power factor	A constant power factor of 0.95 for all DG units according to [2].
PCurt	Static active power curtailment	Active power curtailment of constantly 70% of installed capacity according to [17].
PFCh	Static power factor characteristic	A standard power factor characteristic (Fig. 3a) according to [2].
VDp	Local voltage droop control	Voltage/power droop characteristic is described in Fig. 3b.
CFD	Central fair dispatch	The proposed dispatch algorithm with fairness condition (Eq. 8).
CD	Central dispatch	The proposed dispatch algorithm without fairness condition.

significantly reduce the cost difference between DGs with only a slight increase of total costs. To make the central and local strategies comparable, the nominal voltage at the transformer's secondary side is set to 1 *p.u.* in all simulations. The threshold values of voltage control are also assigned to a range between 1 and 1.03 *p.u.* in strategy **VDp**, which are originally parametrized in range of 1.08 to 1.10 by [4] in order to fully consider offsets of the voltage transmission ratio at distribution transformers and the inherited voltage fluctuation from higher voltage level.

4.3. Simulation Settings

A general setup of grid simulation and dispatch algorithm is presented in Fig. 2. The temporal behavior of grid simulation engine and the dispatch algorithm is schematically illustrated in Fig. 4. For off-line evaluation, both grid simulation and the dispatch algorithm are implemented on one regular PC. As shown in Fig. 2, a power flow solver is chosen as simulation engine using MatPower [18]. Each simulation step starts with a initial power flow calculation, which is to generate the required measurement values for this step. Then, the dispatch algorithm is executed in serial manner. After DGs' set-points are determined, a second power flow calculation is performed to produce the results using these set-points for this step. Both simulation time step and the optimization interval for generation dispatch are set to 15 *min* in off-line test.

In on-line application test, the grid and PV system models are implemented in Opal-RT real time simulator. This a simulation platform contains both a real time target OP5600 and software package ePHASORsim [19] - a solver for studying large scaled power system dynamics in Phasor mode. The simulation time step equals to 1 *s*, while the generation dispatch executes once per minute. The central dispatch algorithm runs in parallel to the grid simulation with a passive synchronization scheme, which is illustrated in Fig. 4. At beginning of each optimization

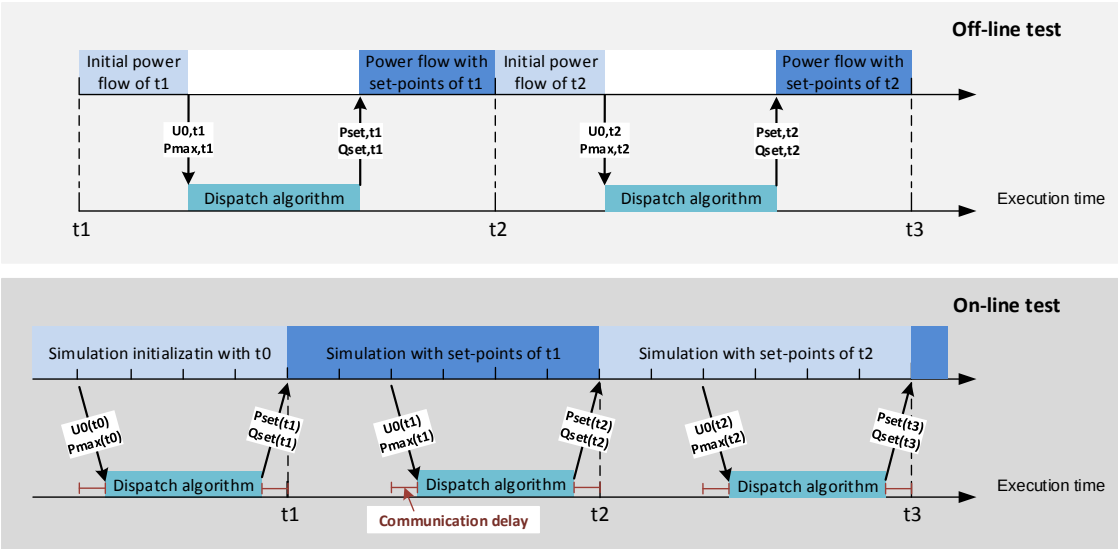


Figure 4: Communication and synchronization scheme between grid simulation and central dispatch algorithm

step, the dispatch algorithm receives present information from the grid simulation. New set-points are determined as soon as they are transferred back to the simulator. After the new set-points are received and updated in the grid model, the simulation begins the next step. The dispatch algorithm is implemented separately on a regular PC. The communication between it and real-time simulator is realized via an Ethernet connection using the UDP/IP protocol. Calculation time and communication delay are also evaluated in the next sections.

5. Case study and results

Three cases are investigated in this work to evaluate the proposed generation dispatch algorithm from different aspects. The first case is applied in order to demonstrate the functional difference of dispatch control strategies on a simple feeder model. The second case is constructed based on a real LV grid and real measurement data in order to reach a realistic evaluation in terms of costs. In the third case, a large generic grid model, which contains both MV and LV levels and a large number of PV generators, is developed. In the last step, all test cases are implemented in the aforementioned real-time co-simulation platform in order to investigate the data transfer and execution time of the proposed algorithm. Although these study cases solely concern PV systems, due to the special context of Germany, it has to be emphasized that application of this algorithm is not only restricted to PV but also can be extended to the economic dispatch problem with all types of DG.

5.1. Case 1

As shown in Fig. 5, the simple feeder model consists of 5 buses, one household load and two PV systems of 7.5 kWp each. Buses 2 to 5 are connected through 1 km LV cables. Due to the reversed power flow and long cable, a critical voltage rise occurs only at bus 5. For PV systems, the same model is applied as in [20].

5.2. Case 2

The model of a real LV grid section of a small town [21], provided by a German utility company, is investigated in the second case study. As presented in Fig. 6, this grid is comprised of two radial feeders and a double ring construction, which is closed under normal operation condition. In sum, 111 households are supplied by a 630 kVA distribution transformer, which is connected to 20 kV MV grid. In this study case, it is assumed that all household have installed a PV system with a random rated power (subject to a uniform distribution) defined between 1 and 10 kWp. Profiles of solar irradiation and ambient temperature in 1 s time resolution are based on real measurement data

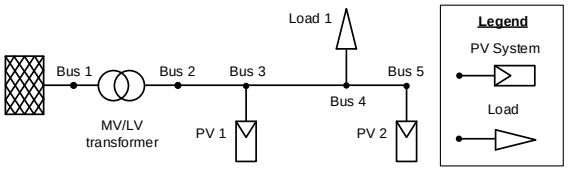


Figure 5: Test feeder with 5 buses (case 1)

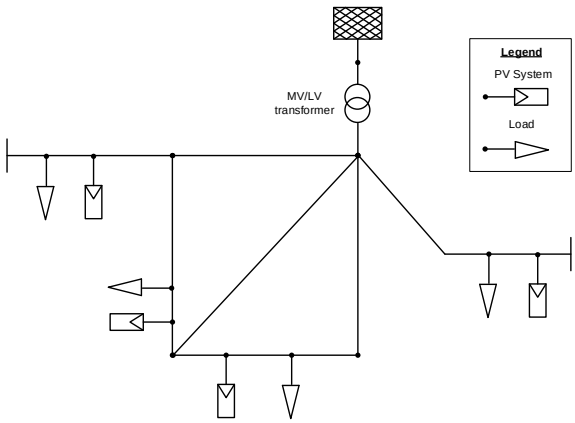


Figure 6: Schematic layout of the LV grid in case 2

on the studied location. A clear-sky day, the May 28th, 2013, is selected as the simulation scenario. Load profiles of households are generated according to German statistics [22]. These profiles describe the electric power consumption of different types of households with the time resolution of 1 s.

5.3. Case 3

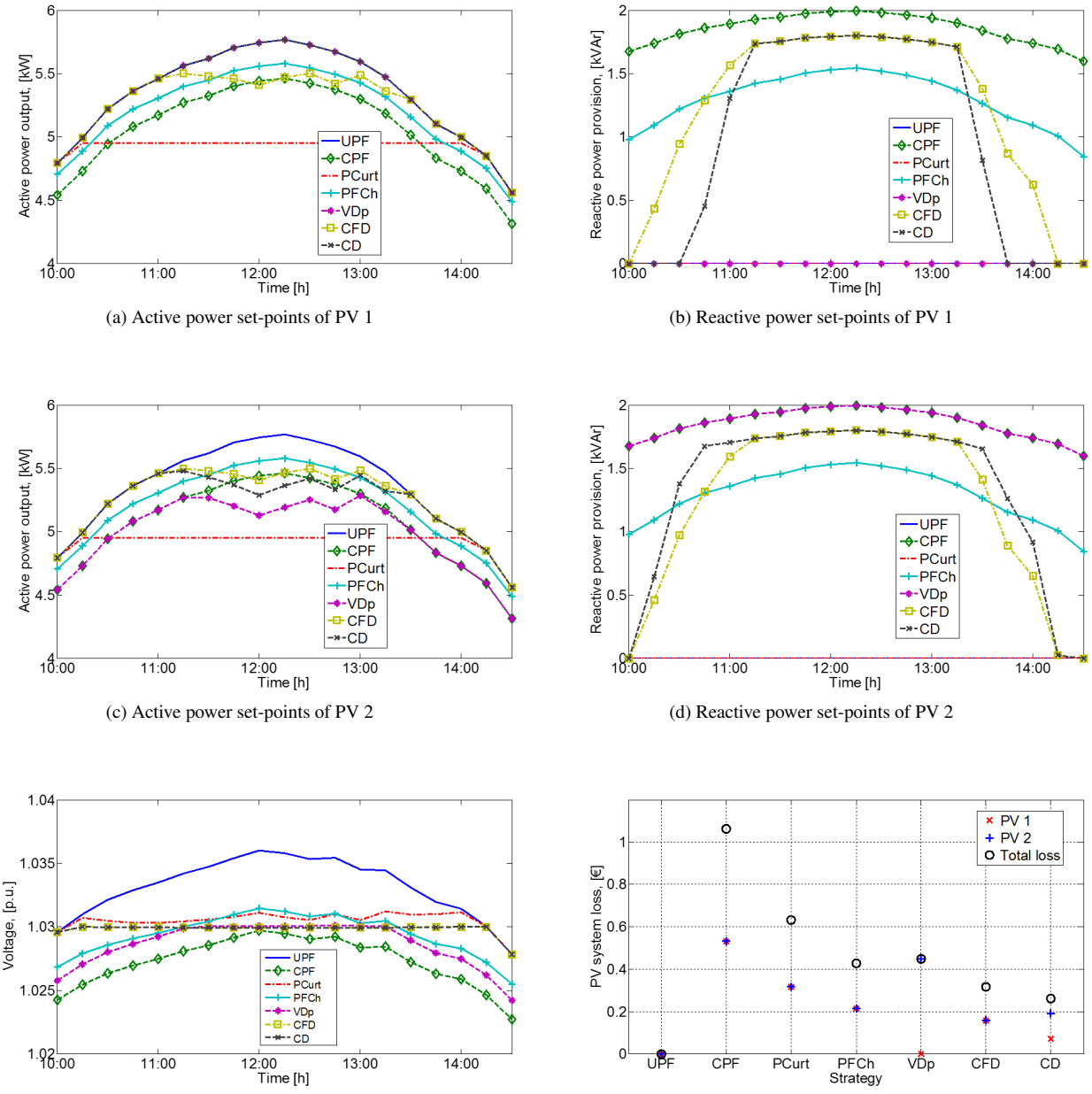
A generic model of a distribution grid, consisting of the CIGRE MV benchmark grid model [23] and several suburban LV grids (each MV node is connected with one or two LV grids), which are generated according to [24], is prepared mainly for benchmarking the online performance of this dispatch algorithm. This model contains in total 752 (a), 1546 (b) or 3211 (c) nodes and 376 (a), 780 (b) or 1591 (c) households by varying the number of connected LV grids. Also hereby, one PV system is connected to each household. The same load and solar profiles are repeatedly applied as in Case 2.

5.4. Results and Discussion

The voltage profile of the critical bus in case 1 between 10:00 and 14:30 is illustrated in Fig. 7e. Hereby, it can be first seen that all strategies can contribute to the regulation of grid voltage at different degree. Especially, the grid voltage is controlled within the permitted limit (below 1.03 p.u.) with strategies CPF, VDp, CFD and CD. Voltage regulation with strategies PCurt and PFCh is insufficient in this investigated period. In addition, central dispatch strategies CFD and CD are able to keep the bus voltage exactly at the boundary during the peak feed-in hours.

Active and reactive power output of PV unit 2 are shown in Fig. 7c and Fig. 7d. With static and local strategies, set-points are configured either too conservatively (CPF) or insufficiently (PCurt and PFCh). For instance, strategy PFCh can not conduct a necessary reduction of active power considering the overvoltage between 11:30 and 13:30, while the maximal reactive potential is already exhausted. Strategy CPF yields maximum reactive power output, which leads to an over-regulated voltage profile during most of the time. According to Fig. 7a and Fig. 7b, no ancillary service is required from the PV unit 1 by applying the strategy VDp. Consequently, PV unit 2 must curtail active power output during the voltage peak period (between 11:30 and 13:00), which would be unnecessary if both of the systems contribute to the voltage control (as CPF demonstrates). By contrast, central strategies CFD and CD try to control the grid voltage more efficiently by utilizing both PV units. By application of CD, both PV units provide reactive power (but in different amount); only PV unit 2 is required to curtail the active power output. This represents the best solution for the grid in terms of total cost (Fig. 7f). With only slightly increasing the total cost, the strategy CFD is able to achieve the same result in voltage regulation as CD. Furthermore, the same set-points for both PV units indicate the same costs for the owners.

In order to compare the costs among PV systems of different size, the specific cost, which is defined as daily losses of a system with respect to its installed capacity, is evaluated. Statistics of these specific costs of a realistic scenario are presented in Fig. 8 (referred to the left y-axis). By analyzing the distribution of specific cost, strategies CPF, PCurt,



(a) Active power set-points of PV 1

(b) Reactive power set-points of PV 1

(c) Active power set-points of PV 2

(d) Reactive power set-points of PV 2

(e) Voltage profiles at bus 5

(f) Costs for PV systems in the simulated day

Figure 7: Simulation results of case 1

PFCh and CFD can be regarded as "fair" strategy, while strategy VDp and CD are considered, by contrast, unfair: some of the PV system have to provide much more services to the grid than others. For this implemented scenario, some PV owners must bear a daily loss of ca. 5 ct/kWp more than other PV system owners, if the "unfair" strategies are used.

Considering the total cost of all PV systems in the simulated day by both case 1 (Fig. 7f) and case 2 (marked as green asterisks Fig. 8), a finding can be concluded. Static control strategies (CPF and PCurt) lead to highest costs

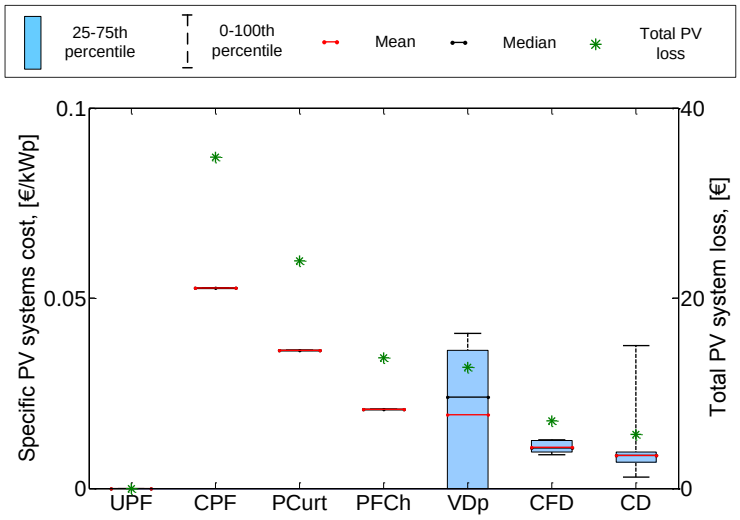


Figure 8: Specific losses of individual PV systems and total losses in case 2

Table 2: Summary of online calculation time of the proposed dispatch algorithm and data transfer duration

	No. of nodes	No. of PV	Average data transfer duration [s]	Max. calculation time [s]
Case 1	5	2	0.005	0.192
Case 2	234	111	0.035	0.731
Case 3a	752	376	0.134	5.484
Case 3b	1546	780	0.225	20.094
Case 3c	3211	1591	0.579	95.081

for PV systems. A fixed curtailment of active power can already contribute to a loss reduction of ca. 20%. Local dispatch strategies (PFCh and VDp) can further reduce the total costs of DGs for grid voltage support. They both generate almost a same amount of losses. A dedicated investigation is necessary to compare the effectiveness of the two local strategies. The central dispatch (CD) strategy achieves the best results in terms of total costs. However, the proposed strategy CFD guarantees that all PV systems provide same service to the voltage support in terms of the specific cost, with only increasing a small amount of cost in total. Therefore, technical (voltage control) and economical effectiveness (loss minimization) are both achieved by the proposed dispatch strategy.

In the last section, the proposed dispatch algorithm is implemented and tested using a real-time grid simulation engine. A summary of the results is listed as Tab. 2. It can be seen here that the time durations for data transfer and for calculation increase linearly and quadratically with respect to the size of grid and PV models. However, for a grid with 3000 nodes and 1500 PV systems, the maximum time demand of the proposed dispatch algorithm is still able to be kept within the predefined operation interval (15 min). The tractable grid sizes can be increased more by using more efficient and parallel solvers such as the CPLEX software. For even larger grids with more than 10000 nodes, metaheuristics such as Simulated Annealing and Evolutionary Algorithms can be used to optimize the set-points.

6. Conclusions

This work proposes a novel central generation dispatch algorithm considering minimization of generation losses and the fair distribution of costs to individual DG unit for to the grid voltage support. Advantages and disadvantages of this central control strategy are analyzed based on numerical simulation using realistic data. Although those static and local dispatch control strategies may still be favored by grid operators due to their simplicity and low implementation cost, the proposed dispatch strategy presents in contrast higher effectiveness in reducing the total costs by DG units,

even with additional concern of fairness. Due to the limited scope of the work, these determined costs can not be considered as the real values of DG owners in practice, as we simplified the assumptions at least on the investment cost for communication infrastructure and the grid reinforcement costs for the DSO. However, the estimated cost differences of these strategies can still give a value for DSOs in making future investment decisions. Also, these results show considerable potential and benefit by the generation dispatch problem at distribution level. In order to test the applicability of the method, the performance of the dispatch algorithm is evaluated with different model sizes in a real time simulation environment. In sum, based on the search of optimal DG set-points, the proposed algorithm determines superior results compared to other strategies, which are mathematically either static or local control methods. Additionally, the computation effectiveness of the proposed method guarantees a reliable online operation mode even for large grids.

As of many other central control methods, the proposed algorithm requires a communication infrastructure and measurement devices for a real application. In order to determine if the proposed strategy is economically applicable and profitable for both DSO and DG owners, further investigations on the system costs including these strategies and necessary investments for real applications should be valuable. Secondly, it is assumed that correct grid information is fully available for the dispatch algorithm. For a real application, the accuracy of state estimation on grid voltage and the quality of online estimation on maximal output of PV systems as well as measurement error may affect the results of the proposed dispatch algorithm. More work concerning these questions should be done in the next steps.

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