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 central generation dispatch algorithm for DGs is presented. 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 real time operation mode.

Index Terms—Distributed generation, generation dispatch, volt/var control, linear programming.

I. 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 operator (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, DG units can actively contribute to grid voltage regulation and to the increase of 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 condition. Through comparison with the 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 real time 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 DSO and aim to operate the whole distribution system optimally considering minimization of grid losses or improving voltage profile. In this work we assume that the voltage problem, caused by power feed-in, is also solved by optimal dispatch of DGs. This optimum denotes the minimum of total cost by all DG owners in the whole system.

• Furthermore, it focuses on a fair distribution of costs considering the size (installed capacity) and the location of DG units. Based on the proposed dispatch algorithm, the same specific costs for all DG units can be achieved without significantly increasing the total costs. This is evaluated on a real LV grid model with measurement PV profiles for the grid area.

• Previous works, discussed in the next section, often consider either active power curtailment or reactive power provision. When both options are considered, there exists certain predefined priority, e.g. active power curtailment is not activated unless the reactive power reserve is exhausted. In the proposed algorithm, both options are
considered simultaneously according to their associated prices in order to determine the optimum set-points for DGs.

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 works are given in Section VI.

II. RELATED WORK

Originally, voltage control and reactive power dispatch are considered as a power system planning problem. It is 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 method. Traditionally, it is characterized as an optimal power flow problem with the typical objective of grid losses minimization [6], [7], [8], [9], to mitigate voltage fluctuations [6], [8], [9] and/or to minimize the total demand of reactive power compensation [10]. Depending on the formulation of objective function and constrains, these problems are solved by linear or non-linear programming techniques.

With the presence of DG in 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 resources. Thus, the voltage problem tends to be solved 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 by 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 voltage 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 employ both of the possibilities offered by DG.

At 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. These 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.

III. PROBLEM FORMULATION

Based on 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 all 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.

A. 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 offered by 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:

\[ c_{EP,i} = Price_{EP} \cdot \Delta P_i \cdot dt, \]
\[ c_{EQ,i} = Price_{EQ} \cdot \Delta Q_i \cdot dt. \]

\( c_{EP,i} \) and \( c_{EQ,i} \) stand for active and reactive power costs in €. \( Price_{EP} \) and \( Price_{EQ} \) are the specific prices for active and reactive energy in €/kWh and €/kvarh, respectively. \( \Delta P_i \) and \( \Delta Q_i \) 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.
Fig. 1: Feasible region of DG’s P, Q setpoints, marked as shaded area

**B. 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:

$$\min f = \sum_{i=1}^{n} (c_{EP,i} + c_{EQ,i}), \quad (2)$$

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

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

$$0 \leq \Delta Q_i \leq P_{max,i} \cdot \sqrt{\frac{1}{\cos \phi_{lim,i}^2} - 1}, \quad (4)$$

$$\frac{-\Delta P_i}{(\cos \phi_{lim,i} - 1) \cdot P_{max,i}} \leq \frac{\Delta Q_i}{P_{max,i} \cdot \sqrt{\frac{1}{\cos \phi_{lim,i}^2} - 1}}, \quad (5)$$

$$u_i = u_{0,i} + \Delta u_i \leq u_{max,i}. \quad (6)$$

where

$$\begin{bmatrix} \Delta \delta_i \\ \Delta u_i \end{bmatrix} = J^{-1} \cdot \begin{bmatrix} \Delta P_i \\ \Delta Q_i \end{bmatrix} = \begin{bmatrix} \frac{\partial\delta}{\partial P} & \frac{\partial\delta}{\partial Q} \\ \frac{\partial u}{\partial P} & \frac{\partial u}{\partial Q} \end{bmatrix} \cdot \begin{bmatrix} \Delta P_i \\ \Delta Q_i \end{bmatrix}. \quad (7)$$

Possible operation ranges of active and reactive power are defined in Eq. 3 and Eq. 4. Herein, change of active power for DG unit $i$ 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 $\cos \phi_{lim,i}$ and the generation potential $P_{max,i}$. 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 setpoints, 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 calculated through the sum of current measurement values $u_{0,i}$ (before dispatch control) and potential voltage deviation $\Delta u_i$ by changing of the generation set-points. On the basis of the power flow equation, the voltage deviation can be linearly estimated according to the adjustment 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 ($S_n$). 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 $\epsilon$.

$$\frac{1}{S_{n_{sum}}} \cdot \begin{bmatrix} S_{n_{sum}} - S_{n_1} & -S_{n_1} & \cdots & -S_{n_1} \\ -S_{n_2} & S_{n_{sum}} - S_{n_2} & \cdots & -S_{n_2} \\ \vdots & \vdots & \ddots & \vdots \\ -S_{n_n} & \cdots & \cdots & S_{n_{sum}} - S_{n_n} \end{bmatrix} \cdot \begin{bmatrix} c_{EP,1} + c_{EQ,1} \\ c_{EP,2} + c_{EQ,2} \\ \vdots \\ c_{EP,n} + c_{EQ,n} \end{bmatrix} \leq \epsilon, \quad (8)$$

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.

**C. 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 dispatch algorithm. Rated power and parameters related to operation limit of individual DG unit are also defined in this step. Finally, the inverse Jacobian matrix is calculated based on power flow model of the grid. This matrix is utilized for estimation of bus voltages.

(2) Update input variables

At beginning of each optimization step, input variables such as present grid voltage and maximal output power of each DG are gathered by the algorithm from the grid simulation. 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 operational 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.

IV. Assumptions for Simulation and Voltage Control Strategies

A. 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.

B. Alternative Strategies for Power Dispatch of DG

The central generation dispatch algorithm and several alternatives, presented in Tab. I, are implemented in order to benchmark the proposed method. The strategy UPF can be regarded as a reference scenario in order to specify the losses associated with other strategies. Strategy CPF and PCur t are static with fixed parameter settings refered to standards. For strategy PFCh and VDp, output power of DG is locally determined according to a predefined control characteristics. The proposed central dispatch algorithm is applied as strategy CFD. Strategy CD is also implemented without the fairness constraints, in order to stress the cost difference of DG units. To make the central and local strategies comparable, nominal voltage at the transformer’s secondary side is set to 1 p.u. in all simulations. The threshold values of voltage are also assigned to a range between 1 and 1.03 p.u. in strategy VDp, which are set in range of 1.08 to 1.10 in reality considering the offset of voltage set-points on secondary distribution transformers and the inherited voltage fluctuation from higher voltage level.

(a) Static power factor characteristics (b) Local voltage droop control

FIG. 3: Local generation dispatch Strategy (PFCh and VDp)

TABLE I: Investigated strategies for voltage control and generation dispatch

<table>
<thead>
<tr>
<th>Index</th>
<th>Strategy</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>UPF</td>
<td>Unity power factor</td>
<td>A reference scenario with unity power factor for all DG units.</td>
</tr>
<tr>
<td>CPF</td>
<td>Constant power factor</td>
<td>A constant power factor of 0.95 for all DG units according to [2].</td>
</tr>
<tr>
<td>PCur t</td>
<td>Static active power curtailment</td>
<td>Active power curtailment of constantly 70% of installed capacity according to [17].</td>
</tr>
<tr>
<td>PFCh</td>
<td>Static power factor characteristic</td>
<td>A standard power factor characteristic (Fig. 3a) according to [2].</td>
</tr>
<tr>
<td>VDp</td>
<td>Local voltage droop control</td>
<td>Voltage/power droop characteristic is described in Fig. 3b.</td>
</tr>
<tr>
<td>CFD</td>
<td>Central fair dispatch</td>
<td>The proposed dispatch algorithm with fairness condition (Eq. 8).</td>
</tr>
<tr>
<td>CD</td>
<td>Central dispatch</td>
<td>The proposed dispatch algorithm without fairness condition.</td>
</tr>
</tbody>
</table>
C. 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, the grid simulation is implemented as power flow calculation in MatPower [18]. Simulation time step and the optimization interval for generation dispatch are set to 15 min. At each simulation step, a pre-calculation (initial power flow) is executed at first. Initial values concerning grid voltage and maximal generator output are updated and prepared for dispatch algorithm. After determining new set-points, a post-calculation is carried out to obtain results of this time step. For online (real-time) application, the grid and PV system models are implemented in Opal-RT ePHASORsim software package [19]. This is a simulation program 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 without additional synchronization. At beginning of each optimization step, the dispatch algorithm receives present information from the grid simulation. New determined set-points are updated as soon as they are transferred back to the simulator. The communication between dispatch algorithm and real-time simulator is realized via an Ethernet connection using UDP/IP protocol. Calculation time and communication delay are also evaluated in the next sections.

V. 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 most realistic evaluation in term 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 only concern PV systems, due to the special context of Germany, it has to be emphasized that application of this algorithm is not restricted to PV.
A. 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].

B. 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 state. 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 are based on real measurement data 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].

C. 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.

D. Results and Discussion

The voltage profile of the critical bus in case 1 between 9:00 and 13:30 is illustrated in Fig. 7a. Hereby, it can be first seen that all strategies can contribute to the regulation of grid voltage. 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.

Active and reactive power output of PV unit 2 are shown in Fig. 7b and Fig. 7c. 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 between 10:30 and 12:00, while the maximal reactive potential is exhausted. Strategy CPF yields maximum reactive power output, which leads to an over-regulation on voltage profile during most of the time. By applying the strategy VDp, no ancillary service is required by the PV unit 1 (its loss equals to zero). Accordingly,
PV unit 2 has to curtail active power output during the voltage peak period (between 10:00 and 12:30), which would not be necessary if both of the systems would contribute to the voltage control (as CPF demonstrates). Also within this peak period, the same tendency, but reaching different magnitudes, in active power control can be observed with PV unit 2 as the central dispatch strategies are applied. By contrast, central strategies CFD and CD try to control the grid voltage more efficiently by utilizing both PV units. If only considering PV unit 2, it feeds in more energy and provides less reactive power according to strategy CFD than strategy CD in order to reach an almost exact performance in voltage support. This is because that different amount of ancillary service is required by the other PV unit according to these two strategies, which is identifiable by comparing the daily cost of the two PV systems (Fig. 7d).

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 are presented in Fig. 8 (referred to the left y-axis). By analyzing the distribution of specific cost, strategies CPF, PCurt, 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. 7d) and case 2 (marked as green asterisks Fig. 8), a finding can be concluded. Static control strategies (CPF and PCurt) lead to highest costs 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. II. 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 grids. 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.

<table>
<thead>
<tr>
<th>Case</th>
<th>No. of nodes</th>
<th>No. of PV</th>
<th>Average data transfer duration [s]</th>
<th>Max. calculation time [s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1</td>
<td>55</td>
<td>2</td>
<td>0.0005</td>
<td>0.192</td>
</tr>
<tr>
<td>Case 2</td>
<td>234</td>
<td>111</td>
<td>0.035</td>
<td>0.731</td>
</tr>
<tr>
<td>Case 3a</td>
<td>752</td>
<td>3/6</td>
<td>0.134</td>
<td>5.484</td>
</tr>
<tr>
<td>Case 3b</td>
<td>1546</td>
<td>780</td>
<td>0.275</td>
<td>20.094</td>
</tr>
<tr>
<td>Case 3c</td>
<td>3211</td>
<td>1591</td>
<td>0.579</td>
<td>95.081</td>
</tr>
</tbody>
</table>

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

VI. 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 of a typical day. Although 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 of DG units, even with additional concern of fairness. These results show at least 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 size 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 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. The necessary investment should also be analyzed in order to determine, if it is economically applicable and profitable for both DSO
and DG owners. 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.

VII. ACKNOWLEDGMENT

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