GRID AND MARKET RELATED INTEGRATION OF RENEWABLE GENERATION UNDER CONSIDERATION OF VIRTUAL POWER PLANTS

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ABSTRACT

A rapidly increasing share of renewable energy resources (RES) poses enormous challenges with respect to a market and grid integration in Germany. Whereas market related integration is encouraged through additional incentives, grid conformity is realized by means of requirements on voltage and frequency support required for RES and decentralized generation (DG). Nevertheless, grid restrictions significantly limit integration and operation of RES. Virtual power plants (VPP) – aggregation of complementary controllable and passive generation technologies – provide the capability to achieve a more efficient grid integration of RES by adapting schedules and compensating fluctuations. However, it is not yet understood, which benefits arise for plant *and* grid operators. Consequently, this paper examines the technical, economic and ecological benefits from grid conform operation of a VPP including RES. Three exemplary cases illustrate the effect resulting from a coordinated operation of VPP and its potential to facilitate and optimize integration of RES in electricity grids.

INTRODUCTION

A continuously increasing share of intermittent generation technologies in Germany demands efficient market and grid integration strategies [1]. In particular, intermittent generation might induce unnecessary and costly grid reinforcements resulting from very few hours of constraint violation. Virtual power plants (VPP) – are frequently discussed as an option with respect to a more efficient grid and market integration of RES. For reasons of enhanced flexibility, the concept of VPP provides a suitable framework towards a more efficient grid integration of RES. However, plant operators who seek to optimize their profit require an incentive to operate in compliance with grid constraints. Therefore, this paper examines the ability of VPP to integrate RES while respecting grid limitations and analyzes profitability and ecological benefits resulting from a coordinated operation of dispatchable generation and loads. For this purpose, an optimization model has been developed simultaneously considering a plant operators' (market related) and a grid operators' (grid related) perspective.

GRID RELATED INTEGRATION - MEASURES

For an increased integration of RES and DG, general responsibility lies with the network operator to ensure a continued safe and reliable grid operation within the specific thermal limits of equipment and voltage limits according to EN 50160. In Germany they are obliged to undertake all measures necessary to warrant stable system operation and give priority to renewable energy in the usage of network [2]. They are therefore compelled to reinforce the grid where necessary and follow a strict precedence order over measures in case of a security constraint violation [3]:

1. Switching operation (§13(1),1,Nr.1EnWG)
2. Reserve capacity (§13(1),1,Nr.2 EnWG)
3. Power curtailment agreements (§8(3) EEG)
4. Power curtailment of conventional power plants and RES (§13(2) EnWG, § 11 EEG)
5. Generation and load shedding, other measures

Switching operation

Currently, grid integration of RES and DG is mainly achieved through conventional grid reinforcement. Besides, operating transformer tap changers for voltage control or changing network topology using separation switches installed at distribution level provides another solution to voltage problems. However, the limited operational range of transformers can make voltage control insufficient for penetration levels of intermittent generation expected for the near future. Besides, operation of separation switches impacts other relevant grid characteristics such as short circuit impedance and thus cannot be used in all cases.

Power curtailment

Curtailment of generation from RES and CHP is only to be induced in case of violation of grid restrictions, which cannot be eliminated by optimized grid operation (switchgear) or grid reinforcement. Plant operators are to be indemnified for their resulting loss by the grid operator. However, compensation fee as well as grid reinforcement can be retrieved through grid fees [4]. This might constitute a lack of incentive for network operators to make efficient use of their assets or promote joint operation of VPP and distribution operators.

Control of reactive and active power

RES and DG units must comply with requirements on their active and reactive power output control. Active power output of generating units in MV and HV grids must be reducible at specific rates [5],[6]. Generators are generally obliged to contribute to network voltage stability by providing reactive power. While loads are to be equipped with compensation equipment that maintains a fixed power factor above $\cos\phi = 0.9$ [6], generators have to be capable of adapting their reactive power output according to specifications set by the system operator [6].

SIMULTANEOUS GRID AND MARKET RELATED OPTIMIZATIONAPPROACH

In order to evaluate the effect and possible benefit from a coordinated operation of RES and DG on electricity grids, an iterative optimization approach has been developed as illustrated in Figure 1.

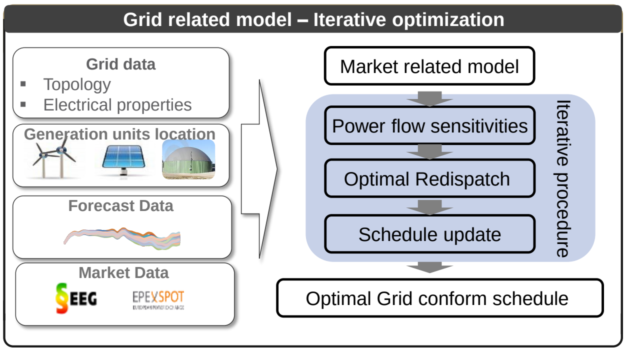

Figure 1: Overview of iterative model for a simultaneous grid and market related optimization of RES and DG units

In order to adequately represent the distribution grid operators' and VPP operators' perspective, the optimization approach simultaneously seeks revenue maximization for VPPs and minimization of curtailment, while also respecting grid constraints. As a result, the approach includes market and grid related operation of VPPs comprising RES and DG.

Market related operation

In Germany's liberalized electricity industry, VPP operators are market driven actors, whose goal is profit maximization. With regard to the grid integration of a VPP's decentralized generation units, the VPP operators are only obliged to meet the grid codes of the respective DSO. Consequently, an optimization model with the objective of profit maximization in the electricity markets is used to determine unit schedules and represent a VPP's market oriented operation. Day-ahead, intraday and reserve power markets are considered in the model. Many distributed generation units (DGs) are volatile RES with a limited predictability. In order to create a robust solution under consideration of forecasting uncertainties, two-stage stochastic linear programming is used as the modeling approach [1]. The scenario generation for representing uncertainties of RES power generation in the stochastic program is based on an ARMA model [11]. For an adequate representation of improvements in forecasting quality during a day, a rolling horizon with multiple optimization runs is employed in the model. The two-stage stochastic approach is used in each optimization run. Whereas the first run includes the day-ahead and reserve market bids in the first stage and intraday transactions in the second stage, the subsequent optimization runs include short term and longer term intraday transaction in the two stages.

Grid related operation

The overall goal of grid and market related operation is to maximize renewable integration into potentially congested grids, while at the same time keeping the profit of VPP at an optimum. In order to include network constraints, the market related optimization problem has to be extended to include the actual output power of the plants in every step of the optimization period. The optimization is then subject to the linear line flow and voltage constraints of the form

$$\vec{S}_l(\vec{P}_b, \vec{Q}_b) \le \vec{S}_l^{max} \tag{1}$$

$$\vec{U}_b^{min} \le \vec{U}_b(\vec{P}_b, \vec{Q}_b) \le \vec{U}_b^{max} \tag{2}$$

where $\vec{S}_l$ and $\vec{S}_l^{max}$ are the vector of line apparent power flow magnitudes and their upper safe operation limits, $\vec{P}_b$ and $\vec{Q}_b$ are the vectors of bus active and reactive power injections, and $\vec{U}_b$, $\vec{U}_b^{min}$, $\vec{U}_b^{max}$ are the vectors of bus voltage magnitudes and their lower and upper safe operating limits, respectively. Furthermore, the optimization is subject to the non-linear power flow equations

$$\underline{\vec{S}}_b = 3 \cdot [\underline{\vec{U}}_b] \cdot \underline{\vec{I}}_b^* = 3 \cdot [\underline{\vec{U}}_b] \cdot \underline{Y}_b^* \cdot \underline{\vec{U}}_b^* \tag{3}$$

where $\underline{\vec{S}}_b$, $\underline{\vec{U}}_b$ and $\underline{\vec{I}}_b$ denote the complex bus power injection vector, bus voltage vector and vector of network current flows into the buses, respectively, $\underline{Y}_b$ denotes the complex bus admittance matrix, the asterisk denotes the complex conjugate and brackets stand for a matrix with the elements of the enclosed vector on its main diagonal. In the attempt to retain the computational efficiency of mixed integer programming (MILP) solvers for the market deployment optimization, the problem has been decomposed such that the market optimization problem and the non-linear power flow problem are solved alternately. The constraints on bus power injections are introduced into the market optimization problem by means of a linearization of (1) and (2) around the solution obtained from a gradient based solver for the power flow problem [7]. The resulting linear constraints can be stated as

$$\frac{\partial \vec{S}_l}{\partial \vec{P}_b}\Delta\vec{P}_b + \frac{\partial \vec{S}_l}{\partial \vec{Q}_b}\Delta\vec{Q}_b \leq \Delta\vec{S}_l^{max} \quad (4)$$

$$\Delta\vec{U}_b^{min} \leq \frac{\partial \vec{U}_b}{\partial \vec{P}_b}\Delta\vec{P}_b + \frac{\partial \vec{U}_b}{\partial \vec{Q}_b}\Delta\vec{Q}_b \leq \Delta\vec{U}_b^{max} \quad (5)$$

with $\Delta\vec{P}_b = \vec{P}_b - \vec{P}_b^0$, $\Delta\vec{Q}_b = \vec{Q}_b - \vec{Q}_b^0$, the deviation from the initial solution $\left(\vec{P}_b^0, \vec{Q}_b^0\right)$ of the power flow problem and $\Delta\vec{U}_b^{min} = \vec{U}_b^{min} - \vec{U}_b^0$, $\Delta\vec{U}_b^{max} = \vec{U}_b^{max} - \vec{U}_b^0$ and $\Delta\vec{S}_l^{max} = \vec{S}_l^{max} - \vec{S}_l^0$, the minimal and maximal deviation of bus voltage magnitudes and maximal deviation of line flows, respectively. The partial derivatives necessary to compute power flow sensitivities and to update the schedule (see Figure 1) can be obtained from inversion of the Jacobi matrix of equation (1) [8]. The Jacobi-matrix as well as the partial derivatives of the line power flows are efficiently calculated using matrix operations [9].

CASE STUDY

In order to evaluate the effect of integrating renewable and decentralized generation into distribution grids under consideration of market related operation, three different exemplary cases are studied:

1. Separate operation of all generation units installed (base) considering feed-in management introduced by DSO (FiMa)
2. Separate operation of all generation units and revised schedule by DSO (NeSe)
3. Joint operation of DSO and VPP operator (NeJo)

The grid under study consists of four nodes with the following characteristics:

Node no.	No. of generators	Total inst. capacity [kW]	Generation units	Connected to node
1	0	0	Slack bus	2; 4
2	2	3,500	Wind power	1; 3
3	3	5,500	Wind power	1; 4
4	4	6000	PV, CHP	3; 4

Table 1: Network node data

Every case is simulated considering historical market data (2011). The time frame encompasses one day with a resolution of 15min.

Separate operation of generation units

In the first case, every generation unit acts as an autonomous agent optimizing its overall profit on the energy market or taking advantage of fixed feed-in tariffs according to current market options in Germany (base) [1]. In case of grid constraint violation, the DSO initiates curtailment measurements to remain network operation within certain limits. Figure 2 illustrates the optimized schedule of a CHP unit (solid blue line) with the bulk of energy generation between 12am and 4pm, which has been chosen exemplarily from the portfolio in Table 1.

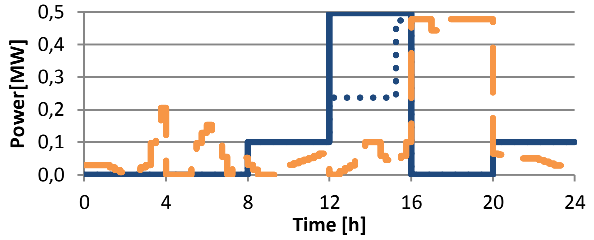

Figure 2: CHP plant power schedule before (solid line) and after feed-in management (dotted line) and after optimization (dashed line)

The dashed blue line indicates the schedule for the same CHP resulting from curtailment measures initiated by DSO after network violation. In the current practice of German grid operators, this is performed by adjusting all generation units of a certain control area to 60%, 30% or 0% of their respective maximal output power [10]. As can be noticed, the generation is cut down approx. half of initially scheduled output power of the CHP (see Figure 2). Generally, the total energy curtailment amounts to 48% compared to the base case without any grid consideration (Table 2 FiMa).

Separate operation and revised schedule by DSO

In a different setting, the network operator revises the plant schedules before they are executed. This is modeled by the iterative optimization process presented in Figure 1. While in this case generation units still operate on the markets individually, the optimization of their schedules is performed with the network constraints incorporated into the schedule submitted by VPP operators (NeSe). In comparison to the case described above a drastic change in operation is observed (yellow dotted line). However, due to the goal of a maximized integration of RES into the grid, curtailment in energy amounts to 35%. Hence, 13% more energy is fed into the grid compared to FiMa case.

Joint operation of VPP and DSO

Finally, a scenario is considered in which the generation units are joint into two groups each one operated as a virtual power plant in accordance with the revision by the grid operator (NeJo). The optimized schedule therefore already considers grid constraints during the planning phase. Figure 3 represents an aggregated profile of all VPP agents. The shape reflects the dominancy of installed PV power. The dashed yellow line – as a result of joint operation – illustrates the cut down in total agent power in case of grid curtailment. In contrast, the dotted blue line displays the cut down initiated by conventional curtailment measures. It generally can be noticed, that the optimized schedule obtained in conjunction with the DSO (market and grid related optimization) allows for the lowest amount of power to be curtailed (see Table 2).

Case	Overall energy feed-in [MWh]	Curtailed energy related to BaSe case
BaSe	48.7	0%
FiMa	25.3	48%
NeSe	31.5	35%
NeJo	34.7	28%

Table 2: Comparison of curtailed and feed in energy

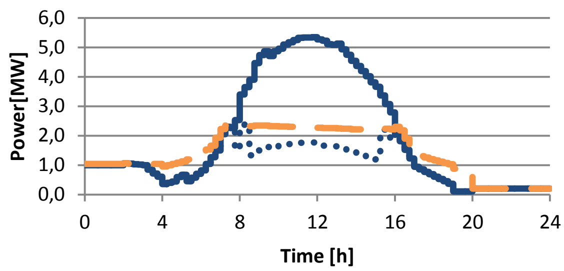

Figure 3: Overall power feed-in (blue) and after feed-in management (dotted) and after optimization (dashed)

SUMMARY AND CONCLUSIONS

A rapidly increasing share of renewable energy resources poses enormous challenges with respect to a market and grid integration in Germany. Hence, strategies for the operation of RES in distribution networks under high prevalence of renewable generation have been identified. Strategies in separate or joint operation with or without cooperation with the DSO have been shown and discussed. It has been demonstrated, that the overall amount of renewable energy fed into the network can be significantly increased in comparison with current curtailment practice of German system operators. This is achieved through factorization of network constraints into the optimization model. However, while market participation of RES is explicitly encouraged by the German renewable energy act [1], the liberalized scheme of German electricity markets does not make possible to foster collaboration prior to plant scheduling. While plant operators might benefit from extended possibilities to partake in the market, it is uncertain what profit for grid operators might result if deferring grid augmentation through such cooperation.

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