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Optimal Use of Energy Storage Potentials in a Renewable Energy System with District Heating

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Abstract

Growing shares of intermittent renewable energy sources in power systems lead to temporal imbalances between electricity supply and demand. Technologies which help to balance the electric grid such as energy storages, demand response or flexible cogeneration concepts are therefore gaining on importance. However, the investigation of these potentials from a system perspective requires a simulation approach that takes into account the interactions between supply and demand side as well as power system stability. While most prior studies utilize either linear optimization models to investigate storage options on a system level, or nonlinear simulation models for power system analysis, the present work utilizes a combination of both approaches.

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1. Introduction

In order to reduce the emissions from electricity generation, Germany aims to cover 80 % of its gross electric energy consumption with renewable energies (RE) by the year 2050 [1]. However, the integration of wind and solar energy into the existing energy supply system has proven to be challenging due to the fluctuating nature of the specific energy offer. As a result, these fluctuating renewable energies (FRE) can not be used for load following or the provision of balancing reserve power in the same way as conventional generators.

Furthermore, the inverter connected FRE plants do not contribute to the electric grid inertia because their rotating masses, if present at all, are electrically decoupled from the grid frequency. This results in an electric grid inertia that is on average lower than in conventional systems and time variant, as it depends on the current FRE production [2].

This can lead to situations where the fluctuating energy offer from FRE must be curtailed because conventional power generation can not be reduced further without endangering the electric grid stability [3]. Similarly, cogeneration plants may be forced to produce electricity to cover the thermal demand in district heating networks. When

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investigating energy storages and demand response, in order to improve the FRE integration, electric grid stability issues as well as coupling effects between electricity and heat generation should be considered.

The TransiEnt.EE project investigates these effects in coupled energy systems, using an integrated simulation approach. For this purpose, the energy system of the city of Hamburg is being investigated as a reference case. Having a well developed district heating grid that covers approximately 20 % of the local heat demand, as well as a broad range of both, small residential and large industrial energy consumers, the considered system is complex enough to investigate coupling effects between energy transmission grids, but still manageable with respect to computational complexity.

1.1. State of the art

Prior studies, e.g. [3–6], utilize mixed-integer linear programming (MILP) to investigate the optimal use of storage technologies in power systems with high share of FRE. In these models, the minimum of a cost function is numerically approximated, while the solution must satisfy certain constraints. The solution vector contains, depending on the scope of the investigation, the operating state, power output and sometimes the capacity of the generation units.

[5] indicates that reducing the must-run generation induced by cogeneration plants can lead to a better integration of FRE. Furthermore, the study identifies demand response with heat pump systems as an effective measure to balance FRE offer and demand. Interactions between these flexibility options with electric power system stability are not investigated, however.

The influence of FRE on power system stability from a system perspective is investigated in two kinds of prior studies. The first, used by, e.g. [3,7] is the incorporation of stochastic analysis in linear optimization models. [3] compares different formulations of unit commitment models that minimizes a weighted sum of possible scenarios of the target function. While this approach leads to significantly higher computational cost as the deterministic unit commitment model, the study finds that conventional power reserve planning is overly conservative and therefore significant financial benefit can be gained by using stochastic optimization.

[7] follows a similar approach by incorporating the results from statistical analysis of wind power production and prediction data into a MILP model. The statistical analysis carried out shows that wind power can meet the technical requirements for balancing power provision with similar reliability levels as conventional generators. The study finds furthermore, that dynamic sizing and allocation of reserves lead to a reduction of system cost, since less power plants are needed and thus more wind energy can be integrated.

The second kind of studies uses system simulation with nonlinear models. Several authors [8–10] use a modeling framework based on a generic power node equation that is used for all components of a power system. The economic dispatch is simulated continuously using model predictive control with different prediction horizons to model day-ahead and intra-day markets. The focus of these studies lie in the investigation of power system operating strategies and the implementation of demand side management from a control theory point of view. [10] shows that secondary balancing reserves can lead to a must-run conventional generation and thus limit the use of fluctuating energies. He also states that heat-led cogeneration plants can secure the demand of secondary balancing power, but the interconnection between balancing reserves and integration of fluctuating energies is not quantified. [11] proposes a heuristic algorithm for the unit commitment problem and uses the results in a system simulation with dynamic models. The study evaluates the changes in control power demand in power systems with high share of wind energy. However, the provision of control power with alternating technologies is not part of the investigation.

1.2. Objective

The present work proposes a simulation approach that allows to simulate the interactions between the demand and supply side of power systems which are coupled to a district heating network. Different measures for the better integration of FRE can be analyzed with this method, while taking into account the power system dynamics and frequency control. Using a case study, the provision of balancing power by FRE generators, load shifting using heat pump systems and the electricity-led operation of cogeneration units in a power system with high share of FRE is investigated.

2. Methodology

The proposed approach uses mixed-integer linear programming for the unit commitment problem and dynamic models based on differential algebraic equations to gain further insight on specific aspects of the system (Fig. 1). These aspects include the simulation of demand side management options which will be further discussed using the example of heat pump systems (Section 3). Starting from single unit simulations of these storage options, the simulation is extended to large pools of consumers using assumptions for the statistical distribution of the components parameters.

The results of these pool simulation allow to derive linearized models which can be integrated into the optimization model (Step 3). The unit commitment schedules resulting from this improved day-ahead planning can finally be used to investigate power system stability in a nonlinear system model (Step 4).

The nonlinear models are implemented in the Modelica modeling language [12] and simulated using Dymola and the DASSL solver [13]. After completion of the TransiEnt.EE project, the resulting model library for the simulation of coupled energy systems will be freely available under the Modelica License [14].

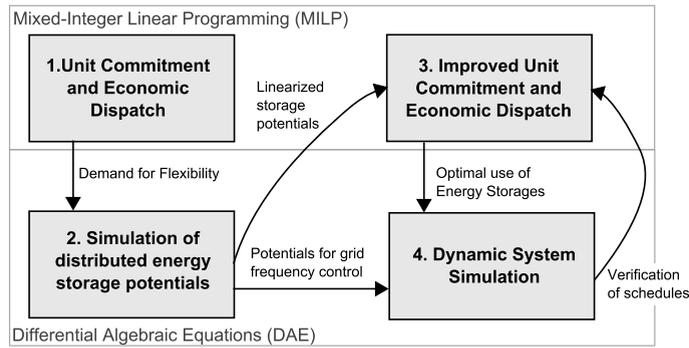


Fig. 1. Proposed hybrid optimization and simulation approach.

2.1. Unit Commitment Model

The optimal unit commitment for a given set of generator and storage units is approximated by using the mixed-integer linear model (1) which minimizes the sum of variable costs $C_{i,t}^{\text{var}}$ considering a prediction horizon of 24 hours for the RE production and load.

$$\begin{aligned} & \underset{x}{\text{minimize}} && \sum_t \sum_i C_{i,t}^{\text{var}}(x) \\ & \text{subject to} && \text{Eqs. (4) to (14)} \end{aligned} \quad (1)$$

Herein, the solution vector x contains the power production, operating state and control power reserve for each unit i and time step t of the prediction horizon.

The variable costs are calculated as the sum of startup-costs (2) and production costs (3).

$$C_{i,t}^{\text{start}} = P_{i,0} \cdot c_i^{\text{start}} \cdot z_{i,t} \cdot (1 - z_{i,t-1}) \quad (2)$$

Herein c_i^{start} denotes the units startup costs (e.g. in €/MW), $P_{i,0}$ is the nominal capacity of the unit, and $z \in \{0, 1\}$ is the units binary operating state.

$$C_{i,t}^{\text{prod}} = c_i^{\text{prod}} \cdot (k_1 \cdot P_{i,t} + k_2 \cdot \dot{Q}_{i,t} + k_3) \cdot \Delta t. \quad (3)$$

In (3), $P_{i,t}$ and $\dot{Q}_{i,t}$ denote the electric and thermal power generation of the unit and Δt is the time step. The specific production cost c_i^{prod} (e.g. in €/MWh) include fuel costs and costs for CO₂ certificates and maintenance. For thermal power plants without heat use, the parameters k_2 and k_3 are set to zero and $k_1 = 1/\eta$. In case of cogeneration units, the parameters are approximated from a nonlinear model of the plant.

The first considered constraint of the optimization problem is the satisfaction of the electric load P_t^L in every time step ($\forall t$):

$$\sum_i P_{i,t} = P_t^L - P_t^{\text{FRE}} \quad \forall t \quad (4)$$

The generation from FRE P_t^{FRE} can be curtailed, which is modeled as a production unit with negative output and production costs above the most expensive generator. Thereby, RE curtailment only takes place if the local balancing of demand is not possible any other way.

The electricity output of the units are subject to power limits:

$$P_{i,t} \geq P_{i,t}^{\min} \cdot z_{i,t} + P_{i,t}^{\text{PR}} + P^{\text{SR}-} \quad \forall i, \forall t, \quad (5)$$

$$P_{i,t} \leq P_{i,t}^{\max} \cdot z_{i,t} - P_{i,t}^{\text{PR}} - P^{\text{SR}+} \quad \forall i, \forall t. \quad (6)$$

This takes into consideration the technical power limits $P_{i,t}^{\max}$ and $P_{i,t}^{\min}$ as well as reserves for primary ($P_{i,t}^{\text{PR}}$) and secondary ($P_{i,t}^{\text{SR}}$) balancing power.

The total reserve power demand must be met and is set according to recommendations of the European transmission operators [15]. The provision of balancing power per unit is constrained by a primary balancing bandwidth p_i^{PR} and the reaction time for secondary reserves t_{SR} and the ramping limit \dot{P}_i^{\max} (Eqs. (7) to (8)).

$$P_{i,t}^{\text{PR}} \leq P_{i,0} \cdot p_i^{\text{PR}} \quad \forall i, \forall t \quad (7)$$

$$P_{i,t}^{\text{SR-}/\text{SR+}} \leq \dot{P}_i^{\max} \cdot t_{\text{SR}} \quad \forall t \quad (8)$$

Furthermore, the units are subject to ramping constraints:

$$P_{i,t} - P_{i,t-1} \leq \dot{P}_i^{\max} \cdot z_{i,t} \cdot \Delta t \quad \forall i, \forall t, \quad (9)$$

$$P_{i,t-1} - P_{i,t} \leq \dot{P}_i^{\max} \cdot z_{i,t-1} \cdot \Delta t \quad \forall i, \forall t. \quad (10)$$

Technical constraints of uncoupled heat generators, e.g. gas-fired peak-load boilers, are modeled with constant power and ramping limits similar to Eqs. (5) to (10) but without balancing power reserves. The heat demand at every site of the district heating network must be met by all heat generators and storage units connected to this site:

$$\sum_i \dot{Q}_{i,t} \cdot s_i = \dot{Q}_{s,t}^L \quad \forall s, \forall t. \quad (11)$$

Herein, s_i denotes the site and $\dot{Q}_{i,t}$ the thermal output of unit i . The coupling of the electric and thermal power of cogeneration plants can be modeled by the linear Equation (12) in which the parameters k_i are determined using a detailed model of the plant.

$$k_1 \cdot \dot{Q}_{i,t} + k_2 \cdot z_{i,t} \leq P_{i,t} \leq k_3 \cdot \dot{Q}_{i,t} + k_4 \cdot z_{i,t} \quad (12)$$

Cogeneration units modeled this way are scheduled optimal with respect to the situation in the electric grid and the district heating grid. This operating mode is referred to as being electricity-led. Heat-led operation can be simulated, by using time-dependent power limits in Eq. (5) which result from the units thermal generation schedule. In this case only the electric power is part of the solution vector x in (1).

Thermal and electric storage units are constrained by their energy capacity boundaries:

$$E_s^{\min} \leq E_{s,t} \leq E_s^{\max} \quad \forall s, \forall t \quad (13)$$

in which the storage capacity

$$E_{s,t+1} = E_{s,t} + \left(\sum_t P_{s,t}^{\text{in}} \cdot \eta_s^{\text{in}} - \sum_t P_{s,t}^{\text{out}} \cdot \frac{1}{\eta_s^{\text{out}}} \right) \cdot \Delta t. \quad (14)$$

is modeled using a constant efficiency for loading (η_s^{in}) and unloading (η_s^{out}). The optimization problem (1) is implemented in Matlab and solved using CPLEX.

2.2. System Simulation

The system simulation model includes the investigated sub grid with generators, consumers and control units, as well as a model for the surrounding synchronous grid (Fig. 2). The power system dynamics are modeled as documented in [2]. The power generator models are based on [16].

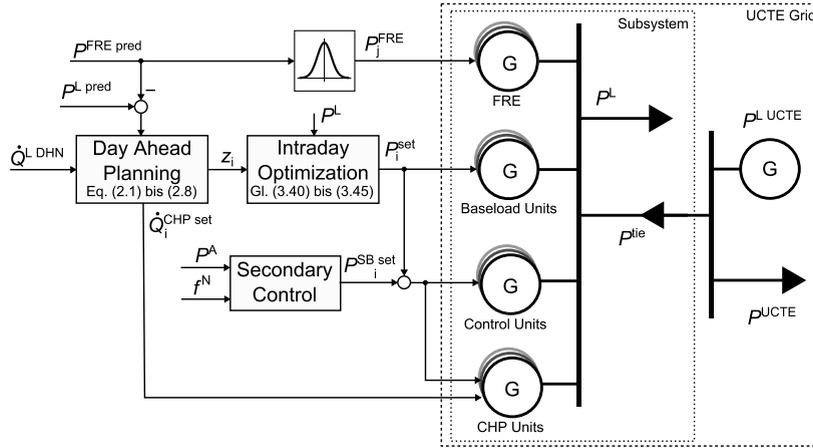


Fig. 2. Boundaries and relevant components of the proposed system simulation model.

By introducing prediction errors, the influence of FRE on power system frequency control can be simulated. The prediction errors are based on normal distributed random numbers depending on the installed wind and photo-voltaic (PV) capacity as proposed by [17]. In case of the wind prediction errors, the resulting white noise random numbers are sorted such that the duration between two sign changes are equally distributed from the interval between 3 and 12 hours. In case of the PV prediction errors, white noise time series are used, but are set to zero during night time.

2.2.1. Economic Dispatch

The unit commitment problem (1) is solved prior to the system simulation. The resulting time series of the units operating states z_i are used in the economic dispatch model which is part of the system simulation. By excluding the unit commitment decision from system simulation, the economic dispatch model becomes convex and can be solved by a simplified step-by-step approach (Fig. 3). In the first step of the algorithm, starting from the initial operating point P_0 , the forward reachable region for each prediction time step is calculated (gray areas in Fig. 3). These reachable regions take into account the operating limits and ramp-rates of the units. In the illustrated example of a system with

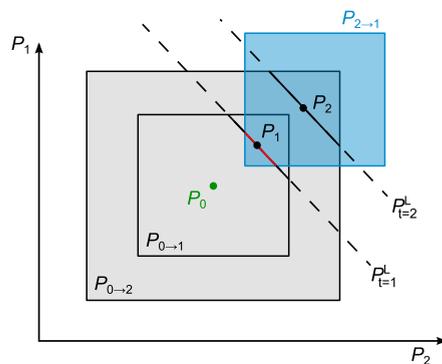


Fig. 3. Step-by-Step approach based on [18] used here to simulate economic power dispatch in a dynamic system simulation. The illustration shows the reachable regions (areas) from a given operating point (dots) and the system load (dashed lines) for a two generator system and a prediction horizon of two timesteps.

two generators and two prediction steps, the solution region considering the load P^L (dashed lines) becomes a section of a line per time step (black continuous lines). Using a simple merit order list the minimal cost operating point for the last prediction time step is then calculated (P_2 , in the illustrated example).

In the second step of the algorithm, the backwards reachable regions are calculated (marked as a blue area in Fig. 3), starting from the operating point of the prediction horizon (here P_2). Once again, the operating limits and ramp-rates are considered. Finally, the intersection of the forward and backward reachable regions (blue and gray areas) and the load is the solution space (red line) for the set point P_1 . This set point is again calculated using a merit-order list and the used as a set point for the generator models (Fig. 2).

The economic dispatch algorithm is periodically calculated every 15 minutes during the system simulation and can therefore be interpreted as a model for intra-day trading.

2.2.2. Secondary Control

Whereas primary balancing control is activated in the entire synchronous grid in case of a grid frequency deviation, secondary control reserves are only activated in the control area which introduced the power imbalance. This is realized in the European grid by using the network characteristic method [15]. According to this method every control area has a secondary controller to minimize the area control error P^{ACE} which takes into account the power transfers on the tie-lines P^{tie} and the grid frequency deviation (Eq. (15)).

$$P^{ACE} = P_{set}^{tie} - P_{is}^{tie} + \lambda_i \cdot (f_0 - f). \quad (15)$$

Herein, λ_i denotes the power system frequency characteristic of the control area i . For example, if a generating unit is lost in another control area, causing a power imbalance $-\Delta P$, primary control power will be activated in all control areas and stabilize the frequency at a lower value $f_0 - \Delta f$. The activation of primary control power in area i will lead to a power flow from area i to the surrounding grid which compensates the frequency induced part of the control area error (P^{ACE}) such that no secondary balancing is activated.

The secondary controller has a proportional-integral characteristic to ensure the tie line power and grid frequency are returned to their set point values (Eq. (16)).

$$P_{set}^{SB} = \beta \cdot P^{ACE} + \frac{1}{T_r} \int P^{ACE} dt. \quad (16)$$

The total secondary control set point P_{set}^{SB} is then distributed to the secondary control providers in the control area. Whereas the participation factors of the control providers in the German power system is a result from trading at control power reserve markets, it is determined using the unit commitment model (1) in this analysis.

3. Flexibility potential of heat pump systems

Heat pumps are considered an effective option for demand response in systems with high shares of FRE because of the thermal storage capacities and the significant electric load. In order to investigate this potential, a reference system is considered, which consists of an air source heat pump, an electric peak-load unit, a hot water storage and the heat consumer (Fig. 4). The system has a bivalent control structure. If the ambient temperature is below the bivalent point T_{biv} , the electric peak-load unit is used to cover the heat demand, which is controlled with proportional-integral behavior. The heat pump is operated if the ambient temperature is above the bivalent point temperature. It is controlled using a hysteresis controller which keeps the storage temperature within a temperature dead-band by switching the heat pump either on or off. Furthermore, the controller uses a time relay, that ensures a minimum time t_{mst} between switches of the heat pump. The heating power \dot{Q}^{HS} is controlled with a PID-Controller such that the set-point room temperature $T_{r,set}$ is kept. The heat pump model consists of an approximation of the coefficient of performance (COP) which is based on the nominal value and the time dependent temperatures of heat source (ambient) and sink (storage temperature). In total the dynamic model has five continuous time states. Thermal stratification in the hot water tank is neglected in the model.

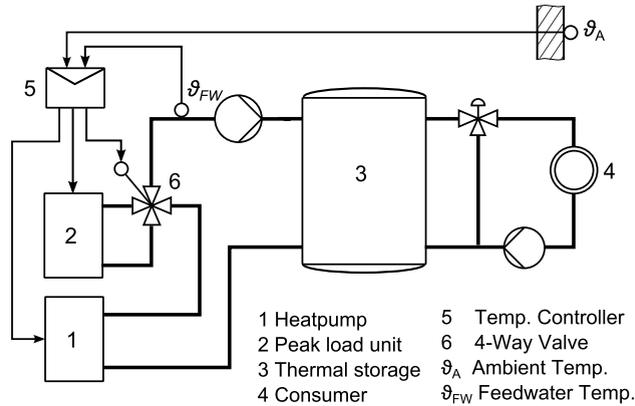


Fig. 4. Investigated heat pump system with electric peak-load boiler and thermal storage.

3.1. Simulation of a pool of heat pump systems

In order to investigate the behavior of a large heterogeneous pool of these reference systems, a parameter set for 100 systems is generated using random numbers. The assumptions and dependencies used to generate this parameter set are listed in Table A.1. Varied parameters include the heat pump dimension, COP, the storage size, the thermal capacity of the building and the control system parameters.

The electric power and storage level (SOC) simulation result for this pool of systems, plotted over the ambient temperature, shows the strong dependence of the system on the ambient temperature (Fig. 5). Grey circles and squares mark system states throughout the simulated year (15 minute output interval) and illustrate the variation of single units with respect to the pool average (blue and red line with symbols). Being ambient temperature controlled, the storage level of the units deviate only at high ambient temperatures, i.e. at low heat demand, from the average values. The simulation result of electric power reflects the bivalent control structure of the systems with a higher slope above the lowest bivalent temperature (here $-7\text{ }^\circ\text{C}$, all units in peak-load operation) and a low slope above the highest bivalent temperature (here $-3\text{ }^\circ\text{C}$, all units in heat pump operation) within the pool. This difference in slope is due to

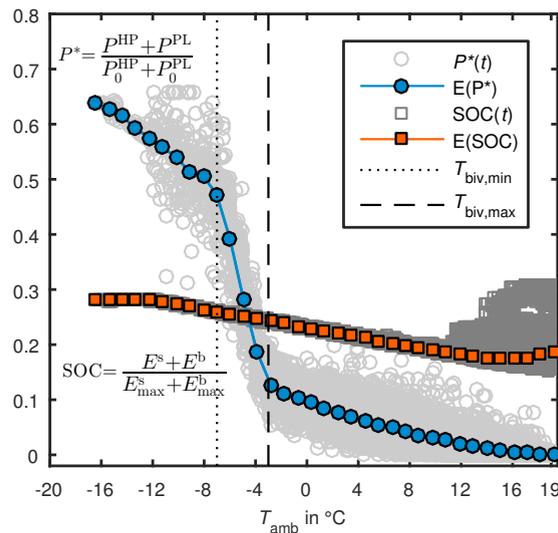


Fig. 5. Simulation result of electric power and thermal storage capacity (SOC) of 100 heat pump systems over ambient temperature. Symbols illustrate discrete system states, Lines show the pool average results which can be interpreted as the expected value of the pool.

the heat pump using the ambient as energy source and therefore having a higher conversion efficiency compared to the peak-load unit.

3.2. Linear formulation and optimal scheduling

Assuming the pool size and the simulated time of the presented result is large enough to capture the system behavior, the pool averaged simulation results can be interpreted as the expected value of the underlying random variables. The storage capacity of demand response potentials can be used to shift the electric load without influence of the satisfaction of heat demand. Using the expected value of power consumption from the pool simulation, equation (14) which has been introduced to model electric storages like pumped storage plants, can be altered to describe demand response potentials (17).

$$E_{DR,t+1} = E_{DR,t} + \left(\sum_t P_{DR,t}^{\text{in}} \cdot \eta_{\text{dsm}}^{\text{in}} - \sum_t E(P_t) \right) \cdot \Delta t. \quad \forall l, \forall t. \quad (17)$$

Here, $E_{DR,t}$ is the average storage level of e.g. the heat pump systems in a demand response pool. $P_{DR,t}^{\text{in}}$ denotes the controllable electric load and $E(P_t)$ is the expected value of uncoordinated demand.

In this sense load shifting using thermal storages is equivalent to storing energy in e.g. a pumped storage plant, the only difference being, that the power flow out of the storage must not be influenced, since it would mean a distraction of the consumer. Therefore only the power flow into the storage ($P_{DR,t}^{\text{in}}$), in this case the heat pump demand, is part of the solution vector of the optimization problem.

To ensure the satisfaction of local demand and since no distinction between single units is modeled, the storage constraint (13) is extended by (17) such that the energy level at the end of the optimization period is equal to the start value.

$$E_{\text{dsm,t end}} = E_{\text{dsm,0}} = E(\text{SOC}_t) \cdot E_{\text{DSM}}^{\text{max}} \quad (18)$$

By integrating the electric power $P_{\text{dsm,t}}^{\text{in}}$ as a solution variable of the unit commitment model, the interactions between supply and demand side can be analyzed. For example, by shifting the heat pump load to a period of low residual load, the curtailment of FRE may be prevented.

4. Case study

In order to show how the proposed simulation approach captures the interactions between the use of demand response, alternative providers of balancing power and frequency stability, a case study is considered which is based on the German network expansion plan for the year 2035 [19]. Assuming the electric demand and the full load hours of Wind and PV production do not change significantly compared to today, the renewable energy offer of this expansion scenario amounts to roughly 60 % of the electric demand. For comparison a possible scenario for the year of 2050 is considered, which assumes the same conventional generation park with increased capacities of RE generators as suggested by the German renewable energy law [20]. The production by FRE is modeled by scaling real production data of 2015 from [21–24] to the installed capacity of the considered scenario.

In order to reduce the complexity of the dynamic simulation only a subsystem of the German power system, namely the system of Hamburg is investigated. For this purpose the German generation park is scaled down to match the local electric load of Hamburg allowing to transfer the results to the situation in Germany. The heat generators and cogeneration units in the model are based on the actual district heating network of Hamburg [25]. Details of the simulated generation park can be found in Table A.2.

Two variations of this system are considered: the reference case (REF) with mostly heat-led cogeneration and without additional storages and an optimized system (OPT) with the following flexibility measures:

- all oil-fired residential heating boilers are replaced by air source heat pump systems and can be used for load shifting. This amounts to an installed capacity of 2060 MW (including electric peak-load boilers). To allow an evaluation of improved power system flexibility due to demand response in comparison to the reference system,

the relation between FRE offer and electric demand is kept constant, by reducing the reference load profile by the uncoordinated heat pump load.

- The power generation planning is electricity-led (allowing to substitute cogeneration units with gas-fired peak-load units in situations with high FRE production).
- Wind and PV generators are participating in balancing control such that positive reserve power can only be provided if curtailment is active (i.e. no permanent throttling) and negative reserve can be provided when RE offer is available. The control power is assigned hourly in order to allow RE generators to participate more flexibly.

4.1. Unit commitment and economic dispatch

Comparing the results of the system OPT35 and REF35 the effect of load shifting with heat pump systems becomes apparent (Fig. 6). As expected the results indicate, that the optimum with respect to variable costs is to shift the load to periods of high FRE offer.

In order to investigate the effect of load shifting and flexible generation planning on the integration of FRE, simulations for the three system variations at different FRE offers were simulated. Using the capacities of the generation parks of 2012, 2035 and 2050 as grid points, the trajectory of the installed capacities at ten FRE expansion states were calculated by linear interpolation. The simulation results of these nine generation parks and three system variations show the share of FRE offer that can be integrated (Fig. 7). At RE offers below 45 % the simulation results show a full integration of the FRE offer for all considered systems. The results are in good accordance with the historic RE shares of the German energy system in the years 2012 to 2015. In the ideal case of complete integration of the FRE offer (blue line with circles) the 2050 scenario leads to a RE share of 74 % of power demand. However, in the simulation result for the reference case (violet line with squares) only 61 % of the electric demand can be covered with the same FRE offer.

In order to show the effect of load shifting with heat pump systems, a variation of the optimized system has been simulated here, introducing only the demand response with heat pump system (red line with diamonds, abbreviation HPS). However, compared with the simulation results for the optimized system, the effect of reduced FRE curtailment is negligible: compared with the reference case (REF50) an additional fraction of 0.5 % of the demand could be met with FRE in the system HPS50. Yet, it should be noted that the substitution of oil-fired boilers by heat pump systems reduces the emissions of the heating system significantly.

The result of the optimized system in the year 2050 (yellow line with triangles) however, shows an integrated share of RE of 65 % of electric demand, significantly reducing the curtailment of FRE by 57 % as compared to the result of the system REF50. This indicates that measures allowing a more flexible scheduling of cogeneration plants and reserve power providers have a major impact on the integration of FRE.

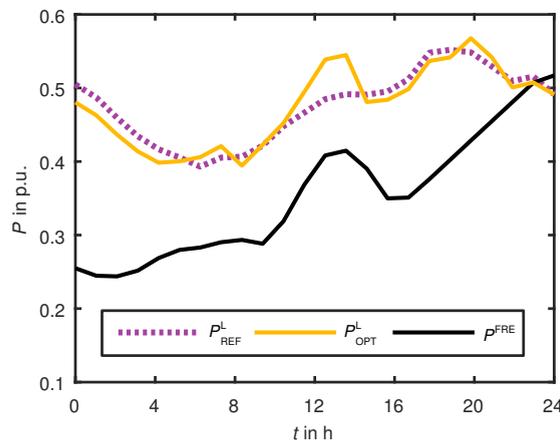


Fig. 6. Load shifting with heat pump systems on the day of minimum residual load for the systems REF35 and OPT35.

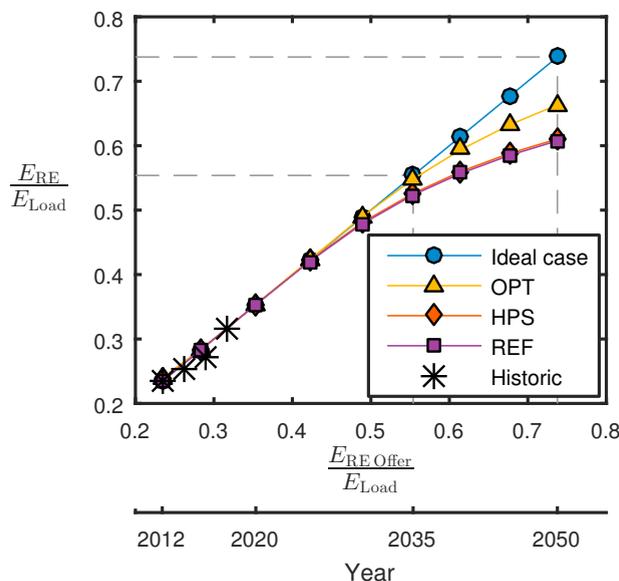


Fig. 7. Simulation result for the usable share of RE in the systems REF and OPT for different RE capacities. The dashed gray lines indicate the situation in the years of 2035 and 2050 according to the German network expansion plan [19] assuming today's RE full load hours and a constant electric demand.

Comparing the presented results with the goal of covering 80% of electric energy demand with RE by 2050, leads to the conclusion that either additional flexibility options (such as further use of energy storages) or an even increased FRE offer (by improving full load hours or increasing the installed capacity) will be necessary.

4.2. Dynamic System Simulation

While the aforementioned results could be gained from linear optimization models alone, the investigation of frequency control requires a nonlinear system simulation which has been carried out for the systems REF12, REF35 and OPT35. The results of these simulations suggest that while the alternative provision of balancing power can allow to shut down conventional power plants in periods of high FRE offer and thereby improve the RE integration, it also has positive effect on the frequency control performance (Fig. 8). In the simulation of the reference system, secondary reserve is provided by the pump storage plant (negative reserve) and a cogeneration unit (positive reserve). In contrast, in the optimized system (OPT35) the negative reserve is provided by RE curtailment throughout the illustrated day and the positive reserve is provided by the cogeneration, biomass and pumped storage plants depending on the current FRE offer. The faster response rate of RE generators reduce the amount of secondary balancing energy used on the simulated day by 26%.

The improved flexibility of cogeneration plant operation becomes apparent in the bottom two plots of figure 8. For example, between 3 and 7 a.m. in the morning of the simulated day, the cogeneration production can not be further reduced in the reference system, as it is scheduled to cover the heat demand. Throughout the simulated day the pump storage is at its maximum energy capacity limit, due to the high amount of must-run generation, and can therefore not prevent the FRE curtailment. Since it is scheduled to provide negative balancing power its operating constraints are further narrowed.

In the optimized system, the negative reserve power is provided by the curtailment of FRE allowing to use the pumped storage plants capacity more flexibly. At about 8 p.m. the cogeneration unit is shut down and the heat demand is covered using gas-fired peak-load boilers which enables the integration of raising FRE offer.

4.2.1. Overall system comparison

The proposed simulation approach allows to investigate the influence of integration measures on cost, emissions and frequency stability (Fig. 9). The comparison of results for the systems REF12 and REF35 shows the benefits

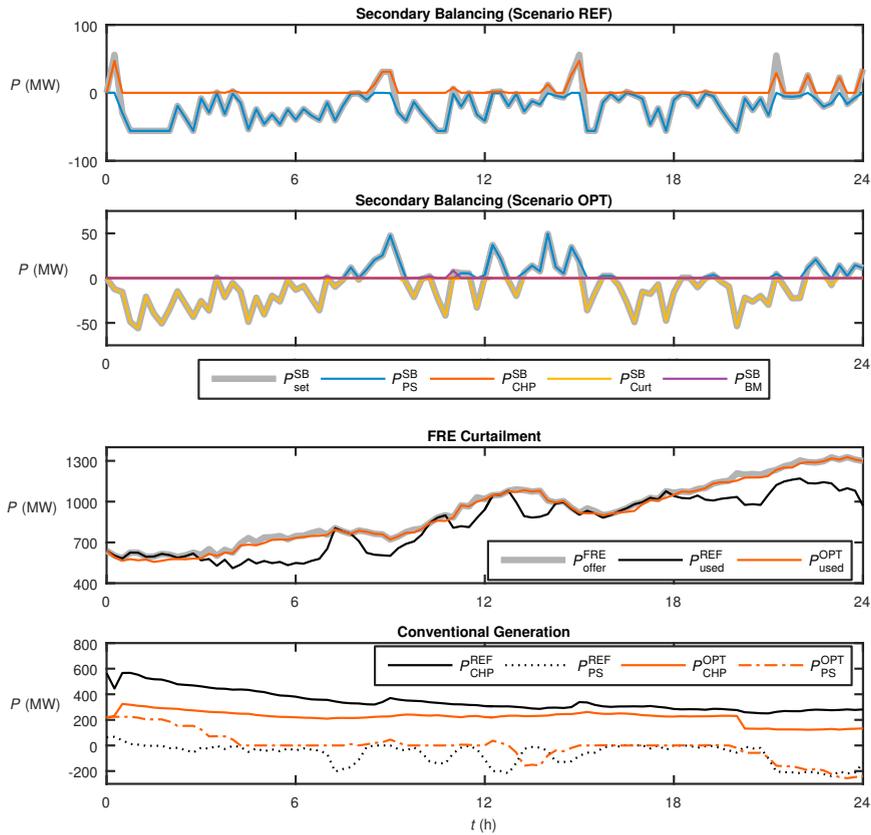


Fig. 8. Simulation result for the influence of flexible secondary control provision on FRE integration in the investigated energy systems REF35 and OPT35.

of RE integration with a reduction of CO₂-emissions by 46 % and 22 % with respect to the electric grid and the total energy system including heat demand, respectively. However, the investments in RE capacity lead to an increase of electricity generation cost of 3.4 % and unscheduled exchange power. The standard deviation of the area control error increases by 37 % due to additional fluctuations, prediction errors and a reduced grid time constant. The optimized system OPT35 reduces the CO₂-emissions by 39 % and 24 % with respect to the reference system REF12 for the

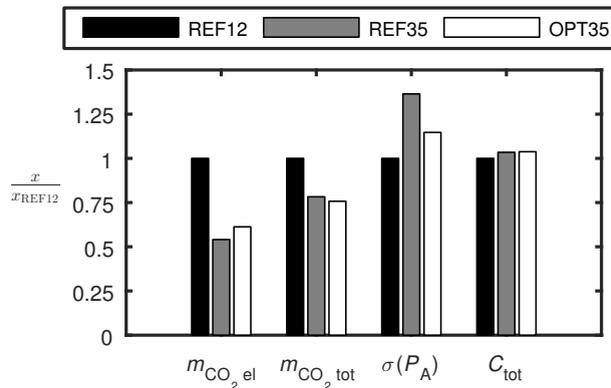


Fig. 9. Simulation results of the investigated systems for the CO₂-emissions in the electric grid ($m_{CO_2\ el}$) and in the entire system including heat demand ($m_{CO_2\ tot}$), the standard deviation of exchange power ($\sigma(P_A)$) and the sum of operating and investment costs (C_{tot}).

electric and total system, respectively. The system cost increase by 3.8 %, which is less than in the reference system due to the higher exploitation of FRE offer. Interestingly, the emissions in the electric system of OPT35 are higher than in the reference case (REF35) indicating that the investigated flexibility measures not only increase the exploitation of FRE offer but also increase the generation from coal-fired power plants while reducing the generation from gas-fired plants. The area control error is reduced in comparison to the system REF35. This improved frequency stability is due to the flexible scheduling of reserve power providers with a smaller time constant than conventional power plants. It should be noted that additional control reserves are still needed to maintain the control performance of today's power system, but not to the same extent as without the investigated measures.

5. Conclusions

5.1. Conclusions

The presented results show that the integration of FRE can significantly be improved by an integrated approach to power system operation planning. The proposed hybrid optimization and simulation approach allows to investigate alternative providers of ancillary services, the use of thermal storages for load shifting and flexible operation of cogeneration units while capturing the interactions between these flexibility options and the integration of FRE.

The proposed simulation approach uses dynamic system simulations and numerical optimization models together. While dynamic models based on differential algebraic equation lead to a deeper understanding of the system behavior and its components, the optimization model based on mixed-integer linear programming allows the cost optimal scheduling of plants and storage options.

One flexibility option that has been discussed is load shifting by using thermal storage capacities in residential heat pump systems. Using a dynamic component model and assumptions for the distribution of the system parameters in large consumer collectives, a simulation with 100 systems has been carried out. The presented results indicate that the expected values of uncoordinated load and storage level can be described as functions of the ambient temperature, which allows the integration in a linear optimization model.

A case study based on the energy system of Hamburg is used to assess FRE integration measures on system level. The simulation results show the importance of electricity-led scheduling of cogeneration plants which can lead to significant reduction of FRE curtailment. The presented results further indicate, that the exploitation of FRE can be increased, if FRE generators are also used as balancing power providers, since conventional units can be scheduled more flexible without balancing reserve constraints. Compared with conventional power plants, the provision of balancing power with RE generators also has a smaller time constant, which leads to an improved frequency control behavior that overcompensates the effect of increased prediction errors and fluctuations.

5.2. Outlook

The proposed simulation approach can further be used to analyze demand response and storage technologies with coupling to district heating networks. Promising topics include the decentralized heat generation with small cogeneration units, as well as the use of large-scale thermal storages and electric boilers in district heating networks.

Furthermore, the dynamic simulation model can be used to simulate contingency events and thereby put the developed operation strategies to test.

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Appendix A. Simulation parameters

Table A.1. Assumed variations and dependencies between heat pump systems based on manufacturer data and the study [26].

Variable	Unit	Assumption
\dot{Q}_n^{HP}	kW	Poisson distributed ($E = 7$)
COP		Normal distributed ($\mu = 3, 7$; $\sigma = 5\%$)
ΔT_{db}	K	Uniformly distributed in $[0, 5; 1, 5]$
ϑ_{biv}	$^{\circ}C$	Uniformly distributed in $[-3; 7]$
t_{mut}	min	Uniformly distributed in $[3; 6]$
C_b	Wh/Km ³	Uniformly distributed in $\{15; 50\}$ (light / heavy construction)
Dependent Variables:		
V_s	m ³	Normal distributed ($\mu = 0.5 \text{ m}^3 / 5.4 \text{ kW} \cdot \dot{Q}_n$; $\sigma = 5\%$)
V_b	m ³	Normal distributed ($\mu = 300 \text{ m}^3$; $\sigma = 10\%$)
G_1	W/K	Linear dependent, $72, 5 \cdot \dot{Q}_n$
\dot{Q}_n^{PL}	W	Linear dependent, $\dot{Q}_n^{PL} = G_1 \cdot (\vartheta_{r,set} - \vartheta_{ref})$
$\vartheta_{r,0}$	$^{\circ}C$	Uniformly distributed in $\vartheta_{r,set} + [-\Delta T_{db}; +\Delta T_{db}]$
$\vartheta_{s,0}$	$^{\circ}C$	Uniformly distributed in $\vartheta_{s,set} + [-\Delta T_{db}; +\Delta T_{db}]$
Constant parameters:		
$\vartheta_{r,set}$	$^{\circ}C$	20
$\vartheta_{s,set}$	$^{\circ}C$	Linear dependent on ambient temperature
η_{PL}		0,98

Table A.2. Parameters of the simulated generation park. Capacities based on [19,25], physical properties taken from [17] and economic properties from [27,28].

Plant Type	P_0 (MW)			No. Units (CHP)			P_{min} (%)	\dot{P}_{max} (%/min)	C_{var} (€/MWh)	C_{start} (€/MW)
	2012	2035	2050	2012	2035	2050				
Brown Coal and Nuclear	700	190		2	1		40	6	25	75
Black Coal	530	230		4 (3)	2(1)		30	8	35	70
Combined Cycle (CCPP)	450	670		2 (1)	3(2)		20	10	63	30
Gas Turbines	120	180		2	3		20	12	122	25
Pumped Storage	130	260		1	1		0	100	0	0
Biomass	130	200	230						0	0
Photovoltaic	680	1230	1380							
Wind Onshore	630	1820	2580							
Wind Offshore	6	380	640							
Others	210	140								
Sum	3590	5280	6500							

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