The System Value of Arbitrage and Balancing Services with Residential Demand Response

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Overview

System operators are seeking novel sources of operational flexibility to cost-effectively and reliably integrate variable and limitedly predictable electricity generation from renewable energy sources (RES). Demand response (DR) allows load to accommodate changes in the RES-based generation, limiting the variability in the net load perceived by the system [1]. When forecast errors are made, regulation services, i.e. controllable generation, energy storage or demand must be procured ahead of time to ensure the system operator's ability to maintain the power system balance in real time. A significant number of residential appliances, such as thermostatically controlled loads, contain some form of inherent "energy storage", which allows these loads to simultaneously be fully responsive and non-disruptive in terms of the perceived energy service. This makes them excellent candidates for DR. Although industrial DR is currently utilized as reserve provider in many power systems and demand-side technologies are sufficiently mature to enable real-time DR control, the potential of residential DR remains untapped [2]. In part, this resistance to the adoption of residential DR programs stems from an inability to quantify the benefits for consumers and producers. Often, power system models employ a simplified representation of the demand-side technology and thereby fail to capture the complex interaction between supply and demand side, especially when storage-type customers are involved [3]. A number of so-called integrated models, with a detailed representation of the supply and demand side, have been proposed recentely [4]. However, these models typically are deterministic in nature, i.e. they neglect the limited predictability of RES-based generation and the associated reserve procurement and deployment.

In this abstract, the focus is on short-term load shifting (i.e. arbitrage) and the provision of regulation services (i.e. reserve provision) via DR with electric heating systems, leveraging the inherent thermal storage in the building stock.

Methods

We employ a state-of-the-art probabilistic unit commitment (PUC) [5] and physical demand response model [4]. The PUC formulation[1] allows calculating an optimal UC schedule given an imperfect wind power forecast, the only source of uncertainty in this abstract, by cost-optimally scheduling conventional generation, energy storage and ADR-adherent load in so-called reserve levels, each with a different deployment probability [5]. The integrated demand-side model, representing the considered buildings and their heating systems, ensures that the thermal comfort of the occupants is guaranteed, regardless of the actual wind power production. The resulting UC schedule is evaluated in terms of operational cost, curtailment of the uncertain wind power production and load shedding, by running Monte-Carlo economic dispatch (ED) simulations for a set of 500 wind power scenarios per day. In the dispatch simulations, a deterministic UC model is executed for each scenario individually, without any reserve requirements, with the unit commitment status set to that obtained from the PUC model and the wind power forecast replaced by the wind power scenario at hand. The deployment of DR-adherent load, energy storage systems and fast-starting units is optimized given the realization of wind power, assuming perfect foresight during dispatch [5].

The simulations are run for a power system inspired on the Belgian power system, assuming a 50% wind power penetration (annually, energy basis). Eight state-of-the-art 450 MW combined cycle gas turbines were added to the system to meet the increased demand for electricity due to the electrification of heating. Details on the power system characteristics can be found in [5]. The number of buildings is assumed to be approx. one million, which is the expected number of detached buildings for Belgium in 2030 [6]. For sake of simplicity, the detached buildings are represented by an "average" building with an average U-value of 0.3 W/K and a ventilation rate of 0.4 ACH (air changes per hour), coupled to a number of representative user behavior profiles [6]. The heating system in each building is an air-coupled heat pump and a back-up electric resistance heater. The user behavior, comfort constraint, heating system and building models are based on [6].

For the numerical analysis below, four representative weeks were selected: week 7 (representing 12% of the year), week 15 (32%), week 9 (30%) and week 25 (26%, i.e. the period of the year outside the heating season).

[1] A unit commitment model is an operational electricity generation system model. Power plants are scheduled and dispatched in order to meet the demand for electrical energy at minimum operational cost [5].

Results

Significant cost savings are to be expected from DR-based arbitrage and regulation services (Fig. 1). On average, the operational cost decreases by 6 pp (percentage points) when considering DR-based arbitrage ("Arb"). An additional one percentage point decrease can be realized if the DR-adherent loads are also allowed to provide regulation services ("Reg"). Remarkably, the value of DR-based arbitrage and regulation services remains unaffected when additional flexibility providers, here non-spinning reserves ("Non-spin. Reserves") and pumped hydro energy storage-based reserves ("PHES-based reserves"), are available to meet the reserve requirements. The presence of these flexibility providers, in particular non-spinning reserves, does decrease the operational cost (on average 4 pp). During the heating season, the operational cost decrease as a result of DR-arbitrage varies between 5 pp (week 15) and 10 pp (week 7). The additional operational cost decrease due to DR-regulation services varies between 1 pp (week 7 and 9) and 2 pp (week 15). Outside the heating season, when only domestic hot water must be supplied, the demand of the electric heating systems, thus the available DR-flexibility, is significantly lower. The operational cost decrease resulting from DR-based arbitrage and regulation is limited (max. 2 pp). Allowing non-spinning reserves and PHES-based reserves results in an expected operational cost decrease of 11%.

The main driver of these cost reductions is an increased utilization of the available wind power and a more efficient scheduling and dispatching of the conventional power plants. On average, the Wind Utilization Factor (WUF) increases from 74.9%-77.5% ("No DR") to 82.1%-84.2% ("Arb.") to 83.4%-85.3% ("Reg.") (Fig. 1). This increase of WUF is the result of (i) shifting demand to periods of excess wind power generation and (ii) an increase in the heating demand, in order to allow DR-based upward reserves (i.e. reducing the heating demand in real-time) without loss of thermal comfort. As a result of increased thermal losses and a higher average indoor temperature, total demand increases 2.5% ("PHES-based reserves", "No DR") to 3.2% ("Spin. Reserves", "Reg.") on average. Consequently, the share of non-renewable energy sources in the electricity geneation mixdecreases at a slower pace than the WUF increases. On average, 67.7% to 66.2% of the demand would be satisfied with electricity generated from non-renewable energy sources in the absence of DR. This drops to 65.6%-64.4% and 65.1%-63.9% when considering DR-based arbitrage and regulation respectively.

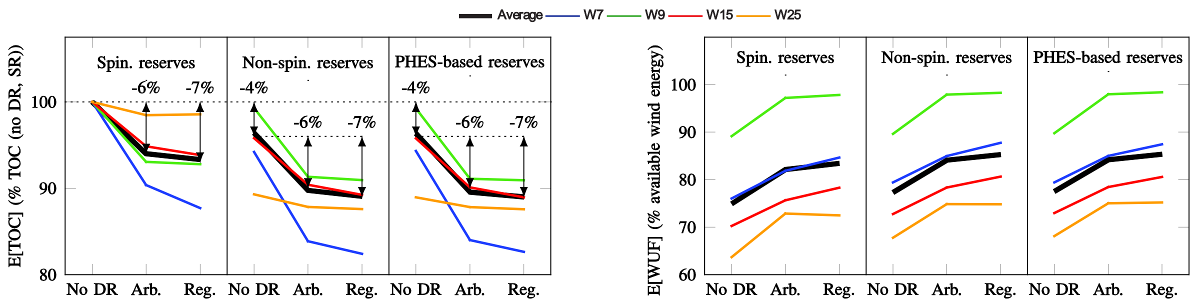

Figure 1: Left: the expected total operational cost (TOC), normalized to the TOC of the equivalent case without DR, assuming only spinning reserves (SR) are available. Right: the expected wind utilization factor (WUF).

Conclusions

Subjecting residential electric heating systems to DR may drastically reduce the operational costs associated with the integration of variable and limitedly predictable RES-based generation. Operational cost savings of 6 pp (load shifting) and 7 pp (load shifting and regulation services) were observed in our case study considering residential electric heating, as the result of a significant increase in the utilization of available wind power. Future work includes (i) an analysis of the system value of thermal discomfort, i.e. the violation of the comfort constraints imposed by the home owners and (ii) studying the impact of limited controllability of the DR-based flexibility.

References

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