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Askeland, M., Jaehnert, S., Mo, B., & Korpås, M.

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Demand Response with Shiftable Volume in an Equilibrium Model of the Power System

Magnus Askeland
Stefan Jaehnert
Birger Mo
Energy Systems
SINTEF Energy Research
Trondheim, Norway
magnus.askeland@sintef.no

Magnus Korpås
Department of Electric Power Engineering
Norwegian University of Science and Technology
Trondheim, Norway

***Abstract*—A linear complementarity model is extended with volume-shifting demand response. The model is an equilibrium model of the power market. In this paper the model is subjected to a scenario for the northern European power system represented by time series for demand and renewable generation. Investments and dispatch are being computed to study the effect of volume shifting demand response on system adequacy and the potential shift in generation mix. The results show that, within certain limits, the system may benefit from demand response. Further, a sensitivity analysis suggest that demand response may not be enough as the share of renewable energy sources increase. From a system adequacy point of view the results show that demand response can reduce the number of hours with load curtailment, but may increase the amount of energy not served with a cost minimization approach.**

***Index Terms*—Demand-side management, energy storage, power generation economics**

I. Introduction

The transition of the European power system towards higher shares of intermittent renewable energy sources (RES) challenges system adequacy. The problem that arises is a mismatch between supply and demand e.g. during hours with low RES production and high demand. In order to address this, physical as well as market-oriented solutions can be implemented. Examples are strategic reserves, capacity markets, storage units and demand response (DR). The latter will be assessed in this paper.

With hourly metering and the ability of demand to react on prices in the energy market, the demand side can provide flexibility to increase system adequacy [1] and/or decrease the total costs. DR is getting more relevant as the technology to enable the possibilities for demand to react on price signals become increasingly affordable and available. Hourly metering and control systems allow consumers to take advantage of price variations in the power market to minimize their expenses without negative impact on the comfort level. System operators can benefit from demand response if the peak load in the system can be reduced, thus lowering investment costs which in turn lead to lower prices for the consumer [2].

According to [3], residential demand response flexibility can either be in the form of delayed use or an energy buffer. A test setup with a smart hot water buffer is demonstrated and implementation on a larger scale is proposed on the grounds of the ability to reduce the electricity cost without a reduction in the comfort level of the consumer.

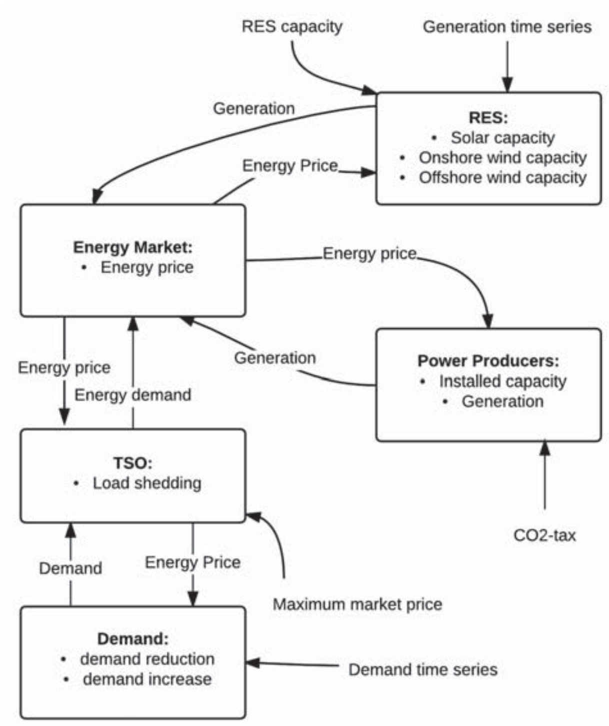

Fig. 1: Schematic of the equilibrium model

Utilization of demand flexibility require systems to control the various appliances. Addressing this, [4] propose a controller that can coordinate operation of appliances in households, depending on price signals to minimize the electricity bill. It is emphasized that such demand flexibility utilization should avoid negative impact on the comfort level of the consumer.

Another source of DR is the increasing share of electric vehicles in the power system. According to [5], non-residential fast charging stations can benefit from lower demand charges if a proposed algorithm is implemented. Meanwhile, this can also benefit the power system by reducing peak load.

A stochastic model to coordinate demand response aggregators and wind power producers is proposed in [6]. The market participants are coupled through bilateral contracts. The approach is able to remunerate the DR investments, increase the profits of wind power producers, and decrease the power system imbalances associated with the stochastic properties of RES.

The following paper provides a mathematical formulation of volume shifting demand response with a rebound effect. Further, a case study provides insights on how the given mathematical formulation will influence the power market equilibrium by the use of a linear complementarity model. The original equilibrium model is described in [7].

The model is based on perfect competition where each market stakeholder makes rational decisions to maximize profit (thermal units) or reduce cost (demand, system operator). Important research questions within this framework are:

- How does demand response influence the need for backup capacity in the system?
- To which extent does demand response affect the electricity price?
- Can demand response increase system adequacy as the share of RES in the system increases?
- What are the limitations of DR as the RES share increases?

II. Methodology

The model is formulated as a linear complementarity problem (LCP) [8]. Based on the linear problems (LPs) for each market stakeholder, the complementarity conditions are derived by applying the Kuhn-Tucker conditions. This leads to the formulation of a linear complementarity problem (LCP) which is a special type of mixed complementarity problems (MCP) [9]. The LCP problem is solved with the modeling software General Algebraic Modeling System (GAMS).

The schematic of the model is shown in Fig. 1 with the decision variables for each market participant indicated as bullet points. Selected parameters are indicated to clarify where these are applied. The formulation of demand response has been developed as described in this paper. A detailed description of the underlying model can be found in [7].

A. Demand Response

The demand response is modeled as shiftable volume with a rebound effect, illustrated in Fig. 2. For any given time step during the operating period the load may be reduced from the level in the time series. This must then be compensated in the future by a subsequent load increase in addition to an assumed penalty related to the delayed use which is referred to as the rebound effect. Hence, the price differences in the energy market need to justify the increase in load due to shifting. An example of the rebound effect is systems that have to run on higher output associated with lower efficiency in order to catch up with the effects of the demand reduction.

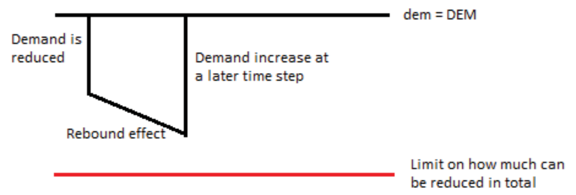

Fig. 2: Concept of volume shifting demand response with rebound effect

The start and end-values for demand decrease is zero. The demand decrease is limited by a maximum fractional value of the demand that may be reduced. The hourly penalty (rebound effect) associated with demand decrease assures that the deviation will be compensated after a short amount of hours.

Demand will seek to minimize the total cost. This means that a demand decrease occur during hours with high energy prices if the energy price is sufficiently low during hours shortly after the demand decrease.

B. Nomenclature

1) Sets:

- h $\in$ H: Set of time steps

2) Variables:

- dem_h [MWh]: Demand.
- $\text{dem}_h^{\triangle}$ [MWh]: Demand deviation.
- $\text{dem}_h^{reduced}$ [MWh]: Amount of reduced demand.
- α_h [EUR/MWh]: Scarcity rent for downwards demand deviation limit.
- η_h [EUR/MWh]: Scarcity rent for demand deviation.
- λ_h [EUR/MWh]: Energy price in the energy market.
- ν_h [EUR/MWh]: Scarcity rent for upwards demand deviation limit.
- ϕ_h [EUR/MWh]: Scarcity rent for reduced demand
- ρ_h [EUR/MWh]: Cost of demand reduction.

3) Parameters:

- DEM_h [MWh]: Demand data.
- DEM^{MAX} [MWh]: Maximum demand.
- L^{dem} [%]: Rebound effect.
- RED^{MAX} [MWh]: Maximum amount of reduced demand.
- $FLEX^{MAX}$ [%]: Maximum downwards demand deviation.

C. Demand Response Problem Formulation

Given demand as a decision variable (dem_h), the objective of the demand side is to minimize total costs over the operating period according to the objective function in equation (1). λ_h is the energy market clearing price which is a parameter in the demand side optimization problem according to a perfect market assumption. However, the combined decisions of all market stakeholders, including demand, will determine the energy market clearing price.

$$\text{Minimize: Cost} = \sum_{h=1}^{H} dem_h * \lambda_h \quad (1)$$

subject to:

$$\forall h : dem_h \geq DEM_h + dem_h^{\Delta} \quad (2)$$

$$\forall h : dem_h^{reduced} \geq dem_{h-1}^{reduced} * (1 + L^{dem}) - dem_h^{\Delta} \quad (3)$$

$$\forall h : RED^{MAX} \geq dem_h^{reduced} \quad (4)$$

$$\forall h : dem_h^{\Delta} \geq -DEM_h * FLEX^{MAX} \quad (5)$$

$$\forall h : DEM^{MAX} \geq dem_h \quad (6)$$

$$(dem_H^{reduced} = 0), (dem_0^{reduced} = 0) \quad (7)$$

Various restrictions limits how the load can be shifted. First, equation (2) couples the demand decision to the demand time series value (DEM_h). The demand may differ from the underlying time series by the use of the variable for demand deviation, dem_h^{Δ}

Further, the amount of demand that has been reduced ($dem_h^{reduced}$) is formulated according to equation (3). A demand reduction need to be compensated later including a rebound effect (L^{dem}). The rebound effect increases the amount of reduced demand if it is carried to the next time step.

According to equation (4), the amount of reduced demand may not exceed a given value (RED^{MAX}) and the amount of reduced demand is set to zero at the start and the end of the operating period according to equation (7).

The demand reduction during any given time step may not exceed the fraction $FLEX^{MAX}$ of the time series value as given by equation (5).

Last, to avoid increased maximum load, equation (6) ensures that the demand never exceed the maximum demand from the underlying demand time series. Since the maximum load remains constant, increased need for infrastructure upgrades will be avoided.

D. Linear Complementarity Conditions

The linear problem in the previous section is reformulated to a linear complementarity problem in equations (8) to (15). Kuhn-Tucker conditions are applied to obtain the LCP problem [8, p.34] [10, p. 145]. The LCP conditions are coupled to the other actors in the model through the energy market.

$$\forall h : \lambda_h - \eta_h + \nu_h \geq 0 \perp dem_h \geq 0 \quad (8)$$

$$\forall h : \eta_h - \rho_h - \alpha_h \geq 0 \perp dem_h^{\Delta} \quad (9)$$

$$\forall h : -\rho_h + \rho_{h+1} * (1 + L^{dem}) + \phi_h \geq 0 \perp dem_h^{reduced} \geq 0 \quad (10)$$

$$\forall h : dem_h - DEM_h - dem_h^{\Delta} \geq 0 \perp \eta_h \geq 0 \quad (11)$$

$$\forall h : dem_h^{reduced} - dem_{h-1}^{reduced} * (1 + L^{dem}) + dem_h^{\Delta} \geq 0 \perp \rho_h \geq 0 \quad (12)$$

$$\forall h : RED^{MAX} - dem_h^{reduced} \geq 0 \perp \phi_h \geq 0 \quad (13)$$

$$\forall h : dem_h^{\Delta} + DEM_h * FLEX^{MAX} \geq 0 \perp \alpha_h \geq 0 \quad (14)$$

$$\forall h : DEM^{MAX} - dem_h \geq 0 \perp \nu_h \geq 0 \quad (15)$$

III. Case Study

A. System Parameters

Demand data is obtained from ENTSO-E vision 4 for 2030 [11] and the time series used in the case study is the aggregation of Belgium, France, Germany and the Netherlands. The thermal power producers included in the case study are nuclear, coal, CCGT and OCGT as presented in Table I. Carbon emissions price data are also obtained from ENTSO-E with a price of 76 EUR/ton according to Vision 4 [11].

Fixed costs are obtained in the form of total investment costs, but are recalculated to annual fixed costs using an interest rate of 5% together with an assumed lifetime for each technology.

TABLE I: Technology characteristics for conventional power producers [12]. Annualized values.

	Nuclear	Hard coal	CCGT	OCGT
Fixed costs [EUR/MW]	313 884	146 660	67 445	51 788
Variable costs [EUR/MWh]	8.22	26.71	46.47	73.37
Technology life [years]	60	25	25	25
Efficiency [%]	34	43	57	33
Emissions [ton/MWh]	0	0.871	0.351	0.606

B. Intermittent Renewable Energy Sources

RES is modeled as time series of the amount of energy generated for 1 MW installed capacity. Hence, the generation can not be controlled and is determined by the time-series value and the installed capacity. The amounts of installed RES capacities are according to the Large Scale RES scenario in the e-Highway 2050 dataset [13]. The time series for wind and solar power are represented by data for Germany and the Netherlands [14], which are assumed to be representative for the entire area that is modeled.

TABLE II: Sensitivity analysis on flexibility

Flexibility	0%	5%	10%	15%	20%
RES capacity [MW]	341 076	341 076	341 076	341 076	341 076
Thermal capacity [MW]	176 528	171 559	171 018	171 018	171 019
RES curtailment [GWh]	20 341	7 815	7 075	6 875	6 809
Emissions [Mton]	41	38	37	37	37
DR usage [GWh]	0	11 890	14 959	15 933	16 229
Average price [EUR/MWh]	43.3	43.3	43.4	43.4	43.4
Load curtailment [hours]	17	11	9	9	9
Load curtailment [MWh]	75 124	81 875	86 204	86 199	86 197

Based on these assumptions, total RES potential is 64.2%, measured as a fraction of total demand. The potential RES injection may exceed the demand during some time steps. In this case the RES has the ability to curtail production and produce below the potential production to avoid overproduction in the system.

IV. Results and Discussion

The following results are based these case studies:

- Fixed RES-share at 64.2% of total demand to assess how different levels of demand flexibility may affect the system.
- Fixed demand flexibility of 10% to study levels of RES ranging from 20% to 100% to assess how demand response performs as the share of RES increase.

It should be emphasized that coal is not present in any of the results because it is not competitive. This may be explained by the carbon emissions tax of 76 EUR/ton combined with the emission factor giving unacceptable variable costs.

A. Demand Flexibility with Fixed RES Share

The RES capacities are fixed according to the e-Highway 2050 dataset [13] to give a potential RES energy share at 64.2% of total demand.

Main results at different flexibility limits are provided in Table II. DR is able to reduce the need for thermal generation capacity in the system due to the load shifting that occurs. The thermal generation capacity decrease originates from an improved utilization of the available RES production. RES curtailment is reduced from about 20 TWh to 8 TWh when comparing the situation with no demand response to the 5% flexibility case. However, increasing the demand reduction flexibility (parameter $FLEX^{MAX}$) beyond 5% of the given demand does not lead to large changes in the equilibrium. RES curtailment is necessary in all cases, indicating a need for storage capacity such as batteries or pumped hydro storage (PHS) to supplement DR for further reductions of RES production curtailment.

Carbon emissions are reduced with the introduction of DR, which related to the decrease in need for thermal peaking capacity. More energy is provided by RES or nuclear power while production from CCGT and OCGT is reduced.

DR reduces the amount of hours with load curtailment, but the amount of curtailed energy increases. The market equilibrium show that it is more economical to accept the load curtailment than to increase the peak load thermal capacity.

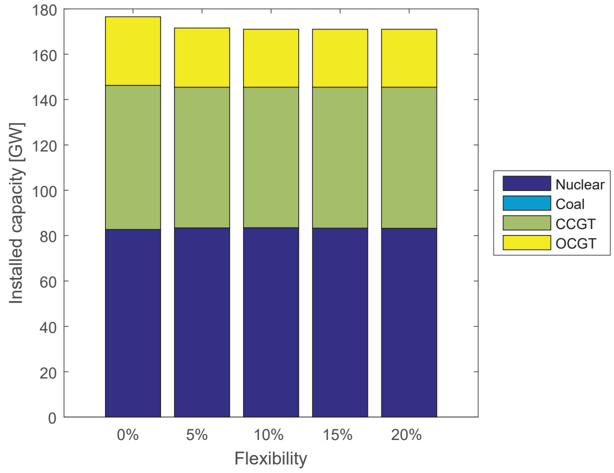

Fig. 3: Installed capacity

Fig. 3 and 4 provides details regarding the thermal mix for five cases with different limits on the maximum demand response. Installed capacities are shown in Fig. 3. OCGT has a relatively large installed capacity relative to the energy produced since it provides the peaking capacity. DR is able to reduce the need for peaking unit capacity. Apart from OCGT, DR has minimal impact on the rest of thermal unit capacities.

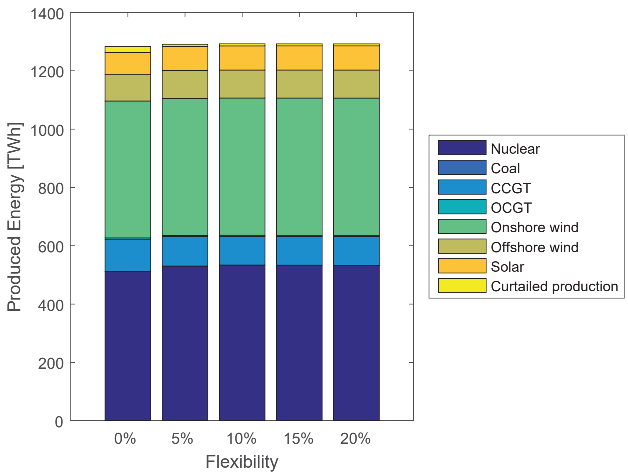

Fig. 4: Produced Energy

Production data is given in Fig. 4. Due to the rebound effect of DR, a production increase is necessary when DR is introduced. On the other hand, the curtailed RES production decreases, limiting the cost of the production increase. Furthermore, a larger amount of production is provided by nuclear power which is a base load unit with very low variable costs, when DR is introduced.

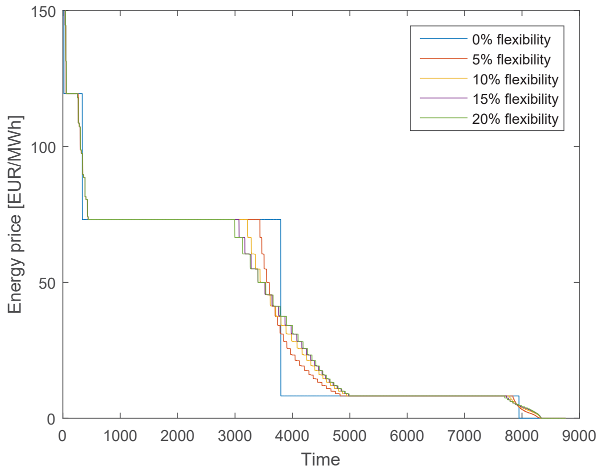

Fig. 5: Price duration curve at 64.2% RES

Production from nuclear power increase with the flexibility of DR. To explain this the price duration curves for the different flexibility settings are provided in Fig. 5. This shows that DR creates price levels between the levels determined by the marginal costs of thermal units. As the demand peaks and valleys are evened out by DR, nuclear power is able to provide a larger portion of the required thermal generation.

DR is able to act in the short term, on the range of a few hours, but do not shift load in the longer term. This indicates that the system would benefit from storage with long-term load shifting abilities such as PHS.

B. Demand Flexibility with Different RES Levels

This section will study how DR performs as the RES share in the power system changes. The demand flexibility ($FLEX^{MAX}$) is fixed at maximum 10% of the time series value while the RES-level is changed.

Table III provide selected result from the cases with different RES shares. In the case with potential RES production at 100% of energy demand the inherent variability of RES means it do not match with the demand profile. Hence, additional capacity in the form of thermal units are necessary. As the RES share increase there is a very modest decrease of 13.1% in the need for thermal backup capacity when comparing the cases with 20% and 100% RES. The need for thermal capacity even at very high RES levels is related to the time steps with a large difference between generation from RES and demand and also long periods with a generation capacity deficit.

At 80% RES and above, the amount of RES curtailment and load shedding increases sharply. This suggest that DR has limited capability to balance a system with high levels of RES and should be supplemented by other storage options. The DR usage is almost unchanged when comparing the 80% and 100% RES cases which suggest that DR has reached a limit regarding how much it can balance the system.

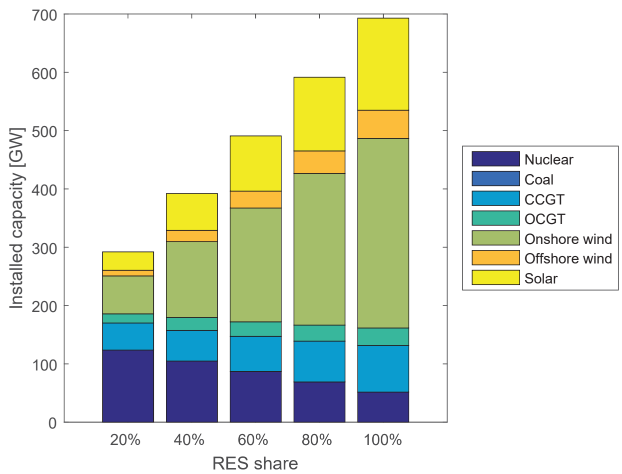

Fig. 6: Installed capacity with increasing RES

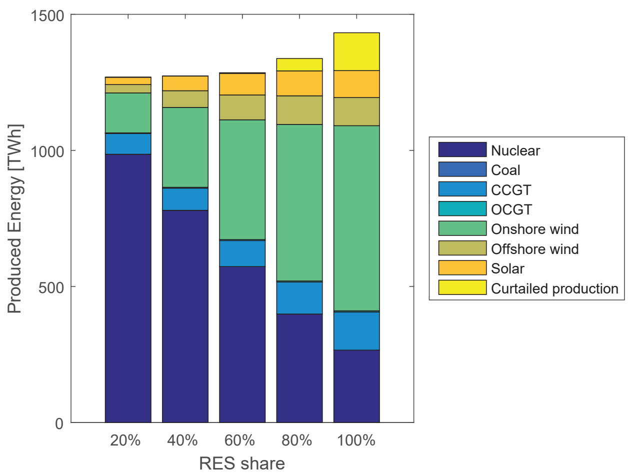

Fig. 7: Produced energy with increasing RES

To ensure higher RES levels as a fraction of demand, a large increase in the installed capacity is required as shown in Fig. 6. While the RES-level increases substantially the decrease in total thermal capacity is rather small. However, the mix between thermal units change when the RES share is increased. Nuclear becomes a smaller part of the generation mix while gas units increase. The thermal mix changes since OCGT and CCGT are more suitable to provide the needed peaking power while the base load energy is partially replaced by RES.

Carbon emissions increase as the RES share increases, which may seem counter intuitive. The variability of RES

TABLE III: Sensitivity analysis on RES level

RES share	20%	40%	60%	80%	100%
RES capacity [MW]	106 265	212 530	318 795	425 060	531 324
Thermal capacity[MW]	185 821	179 613	172 132	166 437	161 526
RES curtailment [GWh]	23	46	2 474	45 448	139 079
Carbon emissions [Mton]	28	31	36	44	52
DR usage [GWh]	4 624	6 792	13 427	18 547	19 602
Average price [EUR/MWh]	44.1	44.0	43.6	42.5	41.5
Load curtailment [hours]	8	5	9	11	12
Load curtailment [GWh]	11	27	81	116	146

give an increased need for backup power from gas units and a decrease in the competitiveness of nuclear power. Increased production from gas power plants is the reason behind the increased emissions at higher RES levels. To avoid this, energy storage options or peaking power thermal plants with a lower emission intensity would be required. The shift towards gas power generation is illustrated in Fig. 6 and Fig. 7.

Fig. 7 shows the amount of energy produced from the various sources at different levels of RES. The thermal generation decreases significantly with higher RES-shares in order to accommodate the situations when injected RES is not enough to cover demand instead of providing significant base load generation.

The total amount of energy generated increases with the RES-share increase despite unchanged demand time series. The reason for this is that an increasing level of RES leads to increased production curtailment as illustrated in Fig. 7. In addition to the increased production curtailment there is an increased energy loss due to the rebound effect of DR.

V. Conclusions

A case study comparing different flexibility limits is carried out given a system with 64.2% RES. Further, the demand flexibility is fixed and the equilibrium is calculated at different levels of RES ranging from 20% to 100%.

Demand shifting has very low investment costs since it mainly requires control systems and no additional storage or generation capacity. In the case study, demand flexibility reduces the necessity of peaking generation capacity. Demand response provides a cost effective alternative to OCGT in situations that can benefit from load shifting.

Even with demand response contributing to maintaining the energy balance, high levels of RES are associated with costs related to more total capacity needed in the system and more dumping of energy. The thermal backup capacity decrease is modest when the RES share increase, which suggest a need for additional storage capacity.

Higher levels of RES may lead to increased carbon emissions due to the need for balancing provided by gas power plants.

DR is able to provide short-term balancing of the power system. However, it lacks the long-term load shifting abilities of for instance pumped hydro storage. Based on previous work [7], DR has properties comparable to short-term battery storage since it relies on short-term price variations on the timescale of a few hours. However, the need for long-term energy storage such as PHS, which may be able to shift large quantities of energy between seasons would be relatively unaffected by the introduction of DR.

Further work should perform additional sensitivity analyses on assumed properties of DR and compare DR to various storage technologies.

Acknowledgements

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