Active demand response with electric heating systems: Impact of market penetration

Impact of market penetration on cost efficiency of active demand response with electric heating systems.

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Abstract

Active demand response (ADR) is a powerful instrument among demand side management strategies to influence the customers' load shape on the basis of price signals or direct load control. It is amply recognized that it may allow achieving benefits for the electric power system. Nevertheless, some difficulties need to be overcome to assure its effective uptake. Among them the complexity of assessing the real potential of such ADR programs to improve the performance of the electric power system. This is mainly due to the strict interaction between the supply and demand for electricity, which demands integrated modeling tools. In this paper an analysis, aimed at evaluating the benefits of ADR programs in terms of electricity consumption and operational costs, both from the final user and the system perspective, is performed. The demand side technology considered is represented by electric heating systems (i.e. heat pumps and electric resistance heaters) coupled with thermal storage (i.e. thermal mass of the building envelope and domestic hot water tanks). In particular, the effect of the penetration rate of ADR programs among participants is taken into account. Different scenarios and system configurations, both at demand and supply side, are examined. Results clearly show that increasing the customers' participation increases the flexibility of the system and, therefore, reduces the overall operational costs. On the other hand, the advantage per individual participant decreases in presence of more players, because a reduced effort for every participating building is requested.

Keywords: Active Demand Response, Heat pump, Thermal Energy Storage, Load shifting, Integrated modeling

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Todo list

1. Introduction

Among the different demand side management strategies, active demand response (ADR) is defined as 'changes in electric usage implemented directly or indirectly by end-use customers/prosumers from their current/normal consumption/injection patterns in response to certain signals' [1]. Such signals could be incentive-based programs (direct load control, curtailable load, demand bidding) and/or price-based programs (real-time pricing, time-of-use pricing, peak pricing), each with its own opportunities and drawbacks [2]. ADR can contribute to a more cost-efficient operation of the electric power system as it may provide the needed flexibility to cope with the intermittent character of some forms of renewables (i.e. wind and PV panels), allowing the demand to match the variable electricity production [3] [4] [5].

Typical residential examples of technologies that can be used for ADR purposes are thermostatically controlled loads (such as boilers, heat pumps, refrigerators and air conditioners), plug-in electric vehicles and deferrable loads, e.g. laundry machines and dish washers [6]. One possibly promising group of demand side technologies above are electric heating systems. These systems could allow to modify their electrical load pattern without affecting the final thermal energy service delivered, thanks to the inherent thermal inertia of the system (both in building envelope [7] and in additional thermal energy storage (TES) tanks [8]). Small scale electric heating systems can be installed in large numbers in the built environment and control access to these loads could be very inexpensive with the advent of communication platforms; so they are good candidates for ADR [6, 9].

However, many challenges remain to be overcome before a large scale roll-out of flexible demand side technologies will emerge. One of these challenges is related to the technical obstacles preventing price signals from being properly transferred to the customers [10], while others are related to the quantification of the benefits for consumers and producers under ADR programs [11]. In order to quantify the effects of introducing such programs, the assessment of the interaction between supply and demand side is of paramount importance, because the electricity prices change with the demand for electric power and vice-versa. When an ADR program is introduced, customers can react to a price signal and modify their demand. At the same time, this asks for an adjustment of dispatch of the electricity generation system, in effect changing the market clearing price at the wholesale level. Ideally, the wholesale price makes up a significant part of the price signal perceived by ADR-adherent consumers. Thus, neglecting the feedback from the demand side to the supply side could introduce major errors in the evaluation. In light of this challenge, the importance of using integrated models for the supply-demand system representation was illustrated in [12], especially when storage-type customers are involved.

This paper aims at analyzing the role of ADR on the integrated supply-demand system and in particular the effect of different penetration rates of such programs among the customers. The demand side technologies considered are electric heating systems (heat pumps and auxiliary electric resistance heaters) coupled with thermal storage in the building stock (both building envelope and additional TES systems). The electricity generation system is based on a hypothetical future scenario where only renewables and gas-fired power plants supply electricity. The analysis is conducted by employing the integrated model presented in Patteeuw et al. [12]. An introduction to this model along with the assumptions on the parameters is given in Section 2. In the model, it is assumed that the electricity demand of the electric heating systems can be partially adherent to the ADR program. The effect of such a partial participation, from hereon referred to as the ADR penetration rate, is assessed in terms of the difference in energy consumption and operational costs for the electricity generation system in Section 3.1. The difference in flexibility due to the hot water storage tank and the thermal mass of the building, considered together or separately, is evaluated in Section 3.2. Moreover, different levels of renewable energy sources (RES) integration in the generation mix were studied in Section 3.3, in order to highlight their effect on the optimization of the system. Section 4 summarizes the observed results.

What is the added value of the paper compared to the literature wrt methodology? This should be made explicit. Also additional numbers on cost savings from other studies.

2. Methodology

In this paper, an integrated operational model of an electricity generation system and a variable electricity demand from buildings using electric heating systems, composed of heat pumps and auxiliary electric resistance heaters, is considered. These heating systems provide both domestic hot water (DHW) and space heating (SH) via floor heating. Thermal energy storage, allowing the model to shift demand for electric power in time, is provided both by the hot water storage tank and by the thermal mass of the building. Section 2.1 describes the integrated model briefly. For details, the interested reader is referred to [12]. In Section 2.2, we detail the case studies examined in Section 3.

2.1. Model description

The integrated model is an optimization problem, in which the overall operational cost of the electricity generation, $cost(g_j^{PP})$, is minimized (Eq. (1)), subject to techno-economic and comfort constraints of both the supply side and the demand side of the electric power system at every time step, j (Eq. (2)- (6)):

$$\underset{g^{PP},d^{hp},T}{\text{minimize}} \quad \sum_{j}^{hor} cost(g_j^{PP}) \tag{1}$$

$$\text{subject to} \quad \forall j : d_{\text{j}}^{\text{fix}} + mp \cdot \Big((1-p^{\text{ADR}}) \cdot d_{\text{j}}^{\text{H,fix}} + p^{\text{ADR}} \cdot d_{\text{j}}^{\text{H,var}}\Big) = \sum_i g_{i,j} + cur_j \cdot g_j^{RES} \tag{2}$$

$$\forall j : 0 \leq cur_j \leq 1 \tag{3}$$

$$\forall j : f(g_j^{PP}) = 0 \tag{4}$$

$$\forall j : d_j^{hp} = h(T_j) \tag{5}$$

$$\forall j : T_j^{min} \leq T_j \leq T_j^{max} \tag{6}$$

This mixed integer linear programming (MILP) model combines a merit order (MO) model of the electricity generation system with a detailed representation of the physical (thermal and electrical) behavior of the dwellings and their electric heating systems. The MO model determines the minimal fuel cost ($cost(g_j^{PP})$) of generating electricity with the conventional power plants (g_j^{PP}). This model consists of a mere ranking of the different power plants in an ascending order of average operational production costs. The MO model considers the minimum and maximum operating point of each power plant ($f(g_j^{PP})$), but neglects ramping constraints, minimum on- and off-times and start-up costs. The validity of such simplified approach in the context of ADR, rather than a complete unit commitment and economic dispatch model, was demonstrated by Patteeuw et al. (Patteeuw et al., 2015). Electricity generation from RES (g_j^{RES}) is represented as a profile. RES-based generation can be curtailed (cur_j). This curtailment is assumed to be free. The only net cost perceived by the system is the opportunity cost of not using the zero-cost RES-based generation available.

In this integrated model, it has been assumed that the ADR-adherent heat pump demand and supply are controlled centrally (direct load control). The redistribution of the operational costs and benefits of ADR among producers and consumers occurs internally and is thus not modeled explicitly. The demand from electricity consists of two parts: a fixed electricity demand profile (d_j^{fix}) and the electricity demand of the electric heating systems for a certain number of buildings (nb). The demand from the electric heating systems can be adherent to an ADR-scheme ($d_j^{H,var}$) or can be fixed to a predefined profile ($d_j^{H,fix}$). The share of flexible and inflexible demand is determined by the parameter (p^{ADR}). The demand from electric heating systems adherent to an ADR-scheme is determined via the demand side model (Eq. (5)). This demand side model is a set of linear equations ($h(T_j)$ which determine the heat pumps electricity demand in order to keep the temperatures in the building and domestic hot water tank (T_j) between the upper (T_j^{max}) and lower (T_j^{min}) comfort bounds (Eq. (6)). The same demand side model is used to predetermine the electricity demand of the heating systems not participating in an ADR scheme ($d_j^{H,fix}$) by minimizing the energy consumption needed to meet the required thermal comfort, not considering the interaction with the supply side model. A detailed description of the integrated model can be found in [12].

2.2. Case studies

The reference case for the analysis is based on a hypothetical future supply-demand system, inspired by the Belgian power system. The electricity generation system configuration is based on a hypothetical future energy mix, consisting solely of gas-fired power plants and RES-based electricity generation. The installed capacity of gas-fired power plants consists of 11200 MW combined cycle gas turbines (CCGT) and 5800 MW open cycle gas turbines (OCGT). The nominal net efficiency of the CCGT power plants varies between 60% and 48% while for the OCGT power plants, this varies between 40% and 30%. Both the fixed electricity demand profile (d_j^{fix}) and the electricity generation by RES (g_j^{RES}) are taken from the Belgian transmission grid operator [13] for the year 2013. In the absence of heat pumps, the peak electric power demand amounts to 13119 MW. With heat pumps, this peak demand occurs at another time, and amounts to 16917 MW. The gas price is assumed to be 25 €/MW_{th}. RES-based electricity generation is assumed to be zero-marginal cost.

Regarding the demand side, the number of buildings (nb) is assumed to be about one million, which is the expected number of detached buildings for Belgium in 2030 [14]. These buildings are represented by an 'average building as suggested in the TABULA [15] project, for which the day zone has a surface of 132 m^2 and the night zone 138 m^2. It is assumed that all these buildings have undergone a renovation of windows, air tightness, walls, floor and roof resulting in low-energy buildings with an overall heat loss coefficient of 30 W/K, corresponding to the economic optimum for Belgium found by Verbeeck [16].

In order to represent the user behavior regarding temperature set points and domestic hot water demand, 52 stochastic user behavior profiles were generated using the method of Baetens and Saelens [17] and aggregated by averaging the predetermined, effective lower temperature bounds [18]. For the weather data, measurements in Uccle (Brussels, Belgium) for 2013 are used. The heating system consists of an air coupled heat pump (ACHP) which supplies heat to the floor heating in the day and night zones, as well as to the storage tank for domestic hot water (DHW). The heat pump is sized to meet 80% of the peak heat demand, the rest of the peak demand is delivered by a back-up electrical resistance heater. The COP of the heat pump is determined according to Bettgenhäuser et al. [19]. The nominal supply water temperature of the floor heating is $35\,^{\circ}C$.

In the reference case, it was assumed that RES-based electricity generation is capable of covering 30% of the electricity demand and it consists of 50% solar and 50% wind energy. The lower bound for the indoor temperature set point is $20\,^{\circ}C$ and $18\,^{\circ}C$ for the day zone and night zone respectively, while, in the reference case, the upper bound are $22\,^{\circ}C$ and $20\,^{\circ}C$ respectively [20]. The maximum allowed operative temperature in the day zone is referred to as $T_{set,max}$ in the rest of this paper. The maximum allowed operative temperature in the night zone is always assumed to be $2\,^{\circ}C$ less. The DHW storage tanks are either 200 l or 300 l, depending on the maximum daily demand at $50\,^{\circ}C$. The upper bound for the DHW storage tank is $60\,^{\circ}C$, which is the maximum temperature up to which the heat pump can deliver heat. In this reference case, the share of flexible demand (p^{ADR}) is varied between 0% and 100%. The first column of table 1 provides an overview of the key parameters of the reference case.

In a second case study, titled 'ADR technology' in Table 1, the difference in ADR flexibility between space heating and domestic hot water provision is evaluated along with measures to increase the available flexibility. In the latter case, the upper boundaries for the indoor operative temperature, $T_{set,max}$(up to $24\,^{\circ}C$), and the DHW storage tank,$T_{DHW,max}$, are varied (up to $90\,^{\circ}C$). The DHW storage tank can be heated up to a temperature higher than $60\,^{\circ}C$ by a back-up electrical resistance heater (maximum temperature $90\,^{\circ}C$). The effect of doubling of the DHW storage tank size is also investigated, so 400 l or 600 l tanks instead of 200 l or 300 l tanks.

In a third case study, titled 'RES share' in Table 1, the impact of the RES share is evaluated by considering two extra cases, namely a 0% and 50% RES share in the final end-energy consumption. Moreover, the relative share of solar and wind energy, and its impact on the performance of ADR programs, is studied.

Table 1: Summary of the key parameters in the different cases studied in this paper. The ADR participation rate is expressed as a percentage of the total demand from electric heating systems. The RES share is expressed as a share of the total demand.

Parameter	Unit	Reference	ADR technology	RES share
ADR participation rate	[%]	0-5-25-50-100	0-5-25-50-100	0-5-25-50-100
RES share	[%]	30	30	0-30-50
$T_{set,max}$	[$^{\circ}C$]	22	22-24	22
$T_{DHW,max}$	[$^{\circ}C$]	60	60-90	60
Tank size	[–]	small	small or big	small

3. Results & discussion

The result section consists of three parts, following the three cases summarized in Table 1. First, the impact of the ADR participation rate is studied on the demand recovery ratio (see below), operational cost of the electricity generation system and potential for peak shaving. In Section 3.2, the influence of the demand side technology and comfort constraints is investigated. Finally, the RES-share and the underlying technologies (solar or wind power) are varied in Section 3.3.

3.1. Reference case

One of the main purposes of this paper is to illustrate the effect on the electricity generation system of a variable ADR participation of customers using electric heating. This effect is presented both from the customers and system point of view. The controllable demand from the electric heating systems was assumed to participate to the ADR program with a variable percentage, namely 0%, 5%, 25%, 50% and 100% (see Table 1, 'Reference' case). When there is no full ADR participation, a part of the consumers are not exposed to the hour-to-hour variations of the electricity generation cost and these minimize their own electricity use. For the customers adhering to the ADR program, the demand is shifted to hours of lower consumption, hence lower electricity costs, and so-called 'valley filling' occurs. Load shifting however leads to additional thermal losses and hence increases overall energy use. The ratio between the observed electrical energy used by the flexible electric heating systems and the minimum electrical energy use of those heating systems is defined as the demand recovery ratio (DRR) [21, 22]. This ratio allows quantifying the thermal losses at the demand side technology and is always greater than or equal to one:

$$DRR = \frac{\sum_j d_j^{HP,var}}{\sum_j d_j^{HP,fix}} \tag{7}$$

Figure 1a illustrates the DRR for the buildings participating in the ADR program. In the case of 0% ADR, the DRR is, by definition, 1 as in this case, there is no participation in the ADR program and the buildings minimize their own electricity consumption. When the buildings participate in ADR, the DRR exceeds one. An important observation is that this

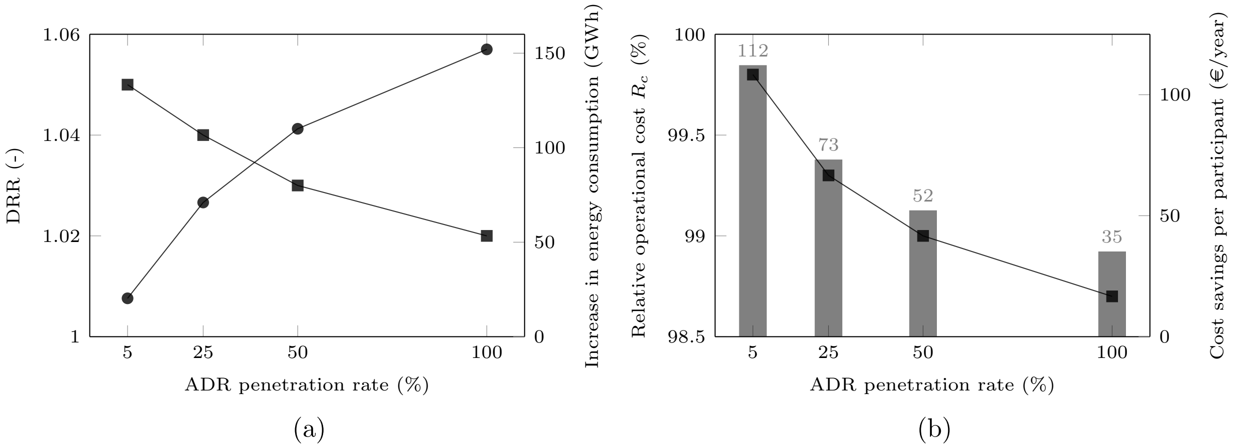


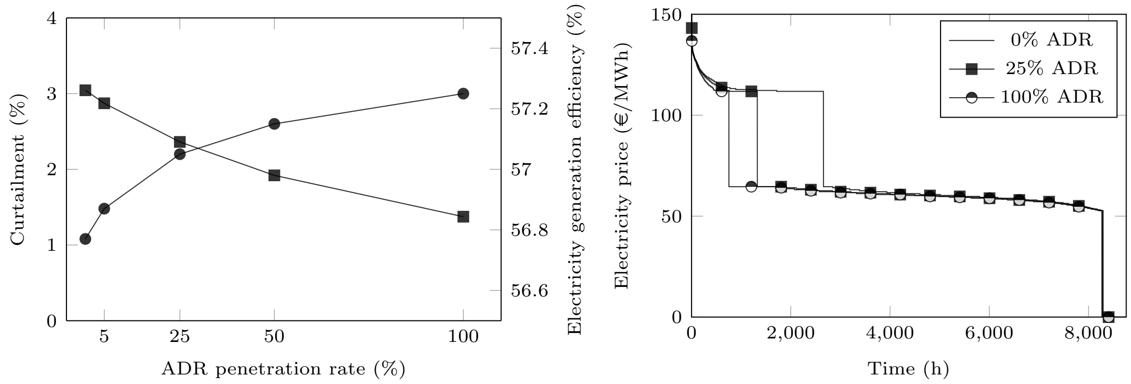
Figure 1: The rate of ADR participation influences the demand response ratio (squares, left axis in Fig. 1a) as well as the total increase in electricity consumption (circles, right axis in Fig. 1a). Increasing the ADR participation rate also has an effect on the operational cost savings, both in total (squares, left axis in Fig. 1b) and per participant (bars, right axis in Fig. 1b).

rise in DRR depends on the DRR participation. When 5% of the buildings are participating, the relative energy consumption increase per dwelling is the highest, as these consumers face the highest incentive to shift their demand, which results in higher thermal losses. When more buildings participate in ADR, the thermal losses per building are lower as can be seen in the DRR. The absolute increase in electricity demand is also shown in Figure 1a. This increase varies between 20 GWh and 150 GWh, which is a small amount compared to the total electricity demand of about 88 TWh. Note that in absolute terms, the demand increases with increasing ADR penetration rates.

Another important effect of the share of ADR participation can be seen on the total operational cost of the system. Figure 1b shows the trend of the ratio, R_c, between this total operational costs with ADR and the total operational cost in the case of no ADR participation. The operational cost includes only fuel costs and thus no investment costs, ramping costs, CO_2-emission costs or start-up costs. The maximum costs reduction for the considered configuration of the system was assessed to about 1.3%[1], which seems a limited percentage but corresponds to an absolute value of about 35.5 M€per year. In terms of CO_2 emissions, these are, in this case, at most reduced by 0.29 $Mton/year$. At current EU ETS CO_2 emission right price levels, the operational cost reduction stemming from CO_2 emission reductions is thus an order of magnitude smaller than the operational cost reduction due to fuel cost savings.

The decrease in operational cost and CO_2 emissions are due to the greater demand flexibility which allows a more efficient operation of the power plants and a reduction in curtailment of electricity generation by renewable energy sources. This is demonstrated in

[1]The optimality gap used in the mathematical optimization of the model is 0.1%, an order of magnitude smaller than the operational costs reduction.



(a)

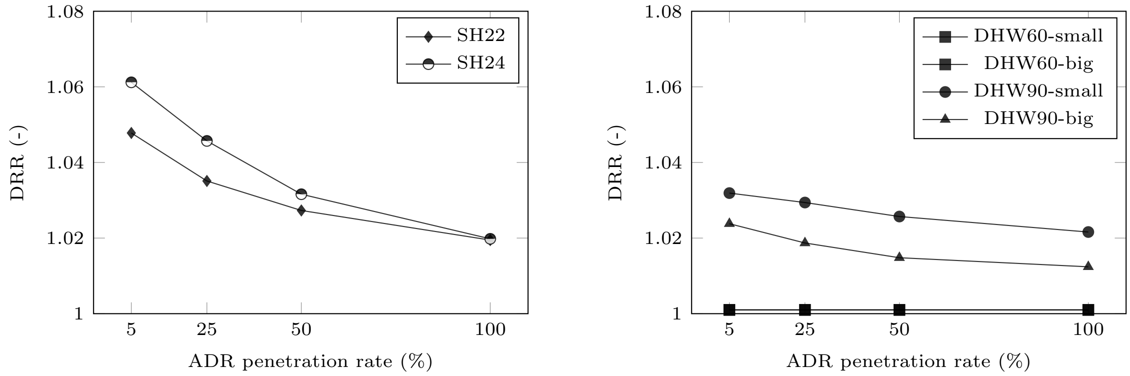
(b)

Figure 2: Curtailment as a percentage of the available RES-based generation (squares, left axis in Fig. 2a) and average electricity system generation efficiency (circles, right axis in Fig. 2a) and price duration curves 2b for different ADR penetration rates.

Figure 2a. The average electricity generation efficiency[2] shows a slight increase, while the curtailment is halved by increasing the ADR participation from 0% to 100%. Figure 2b, shows the electricity price duration curve. The electricity price is here determined as the marginal cost of the most expensive unit running in accordance with the MO model. Three different main plateaus can be detected: (i) for a short number of hours (about 400) the price is zero, when the RES fully satisfy the demand; (ii) an intermediate price level set by the CCGT power plants; (iii) the highest price corresponds to the OCGT power plants covering the peak demand. The duration of the peak electricity price decreases with an increasing penetration rate of ADR, from about 3000 hours to 1000 hours. This is due to two effects, the first being the load shifting from peak hours to hours where the CCGTs can cover the load. The other is the increasing of demand above the minimal operating point of the CCGTs in order to avoid the use of the OCGTs with lower efficiencies. Note that already at an ADR penetration rate of 25%, the reduction in high price hours is very close to the final value of about 1000 h, which illustrates the reduced marginal impact on the final price of increasing the ADR participation. Additionally, the duration of the plateau where the price is zero, increases as the ADR participation increases. The demand is shifted away from hours where the CCGTs set the price, towards hours with excess RES-based electricity generation. This shift is less drastic in terms of duration: there are an additional 25 h of zero electricity prices in the case of a 100% ADR penetration rate compared to the case without ADR.

Finally, under the hypothesis that the operational savings could be entirely divided among the participants of the ADR scheme, the possible annual cost saving per customer was evaluated (Figure 1b). The yearly cost saving per building goes down when there

[2]The average electricity generation efficiency is here defined as the total volume of electrical energy produced by the gas-fired power plants divided by the total amount of primary energy needed to produce that electricity.



(a) (b)

Figure 3: DRR by varying the ADR penetration rate for the two ADR technologies considered in different configurations. Figure 3a shows the DRR for different temperature set points of the space heating system, without flexibility in the DHW production. On the other hand, Figure 3b showsh the DRR for different sizes and set points of the DHW tank, without flexibility in the space heating system.

are more participants, meaning again that a lower effort (i.e. load shifting) and lower benefit (i.e. operational cost savings) per participant is attainable when more consumers are involved. This analysis gives an idea of the operational cost benefit that the ADR can bring not only to the system, but also to the customers, even if the cost evaluation is not quantitatively comprehensive of all the ADR effects (e.g. reduced investment costs, start-up costs, ramping costs). To evaluate the economic viability of such an ADR program, the energy cost savings should be compared with the investments required to implement the necessary ADR technology in every dwelling and the deferred investment in peak production capacity (see Figure 6).

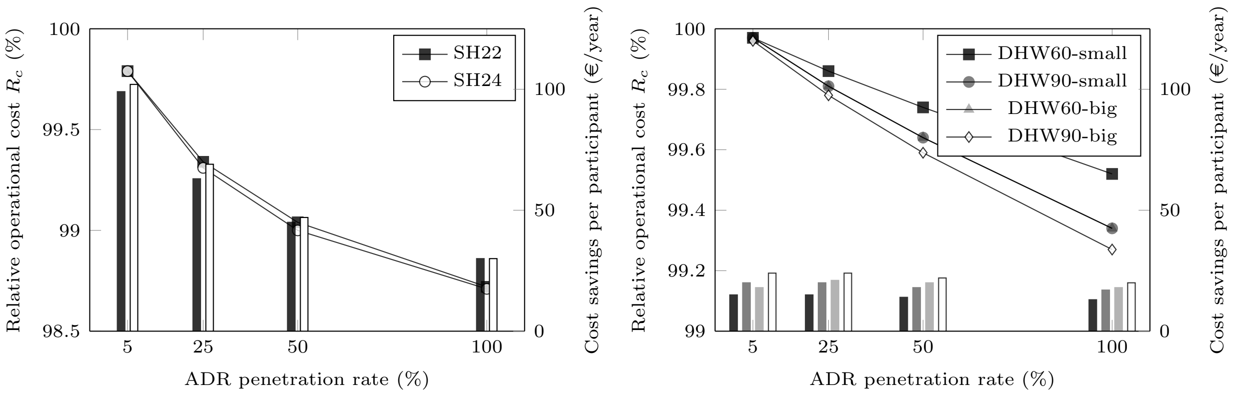
We should add here the peak shaving potential and move part of the discussion. Do we have the results with both SH and DHW?

3.2. Influence of the ADR technology

The results reported above take into account both the flexibility provided by the thermal mass of the building and the flexibility of the DHW tank, as the heat pump can supply heat to both. In this section, the two different types of thermal storage are analyzed separately in order to evaluate their own intrinsic potential. This is meaningful considering that installations are possible in which the heat pump is dedicated only to space heating or only to domestic hot water production. Again both the customer and the system point of view are analyzed by means of the two parameters DRR and R_c. Figure 3 shows the demand recovery ratio for all the configurations of the demand side technologies under study ('ADR technology' case in Table 1).

For the scenarios where only the flexibility of the building thermal mass is allowed, the electricity consumption for DHW is assumed to follow a fixed profile, and vice versa[3]. As already mentioned in Section 2.2, the flexibility in the building thermal mass stems from

[3]When there is only flexibility in the building thermal mass allowed, the electricity consumption for DHW



(a) (b)

Figure 4: Influence of increasing the upper temperature bound for space heating (Figure 4a) and the size and temperature setpoint of the domestic hot water production systems (Figure 4b) on the relative operational cost and the cost savings per participant. The lines and markers correspond to the relative ooperational cost (left axis) while the bars indicate the cost savings per participant (right axis). The colors of the bars and markers are related to the ADR technology set point.

the difference between the lower and upper bound of the indoor temperature set point. The average lower bound for the building is around $20\,°C$, while two possible upper bounds are studied in this section, namely $22\,°C$ and $24\,°C$. As the latter is already high for the inside winter comfort condition, it is worthless to examine higher inside temperature set-point bounds. As expected the DRR increases for a higher inside boundary temperature, because more flexibility translates in more energy consumption/losses. At 5% ADR participation, the relative difference in electricity demand is the highest, corresponding to 19 GWh when T_{set} is $22\,°C$ and 24.4 GWh when T_{set} is $24\,°C$. Moreover, when the ADR penetration rate increases, the two DRR curves tend to coincide.

Looking, on the other hand, to the operational costs (Figure 4a) for the two space heating temperature set points cases, their difference is negligible. The savings per building participating in the ADR program are similar to those examined in the previous section (Figure 1b). All these observations lead to the conclusion that it is not necessary to make a dramatic change in the upper bound for the inside temperature: a $2\,°C$ dead band for the variation of the internal temperature is a standard operational range for space heating thermostats and it demonstrated to be sufficient to comply with the flexibility requirements from the electricity generation system. Furthermore, this is also confirmed by the average daily zone temperature during the year: in the first case with $T_{set,max}$ is $22\,°C$, it is $20.4\,°C$, while in the second case with $T_{set,max}$ is $24\,°C$ it is $20.5\,°C$, meaning that the system reaches rarely the upper bound temperature and tends to be close to the lower bound (as it happens in case of no ADR), especially for higher ADR penetration rates. The necessity for a longer exploitation of the upper bound of the temperature dead band is more evident for a reduced

is a fixed profile which equals the profile that corresponds to the minimal electricity consumption needed for providing DHW.

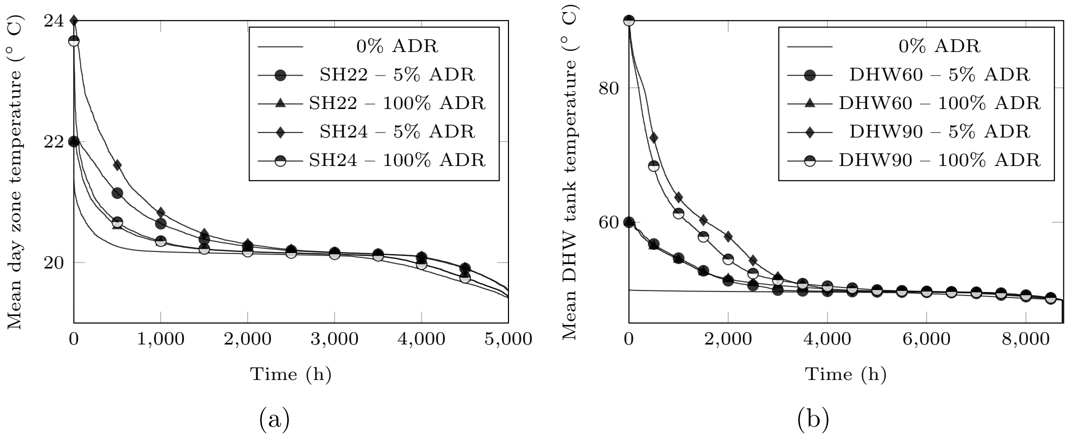


Figure 5: Temperature duration curve of the operative temperature in the building (Figure 5a) and average temperature of the DHW tank (Figure 5a). For the building operative temperatures, only the hours during the heating season are shown.

ADR penetration rate, as illustrated in Figure 5a.

Similarly, the analysis was performed for the case in which thermal flexibility is only allowed in the DHW tank. The configurations analyzed differ for the upper bound temperature of the stored hot water, which can be set at $60\,°C$ or $90\,°C$ (otherwise the DHW is normally delivered to the users at $50\,°C$) and for the size of the tank: normal size (the volume varies from 200 to 300 l on the basis of occupants number) or double size. Again more flexibility, i.e. bigger tank and higher boundary temperature, results in higher DRR (Figure 3), while the difference in relative operational costs is limited (Figure 4). In particular, as far as the energy consumption is concerned, when the upper bound temperature is set at $60\,°C$, the increase in consumption is below 0.5% regardless of the tank size. On the contrary, when the upper bound temperature increases up to $90\,°C$, it seems that the effect of the higher temperature bound is of greater influence than the doubling of the volume. In absolute terms, the increase in energy consumption is 12 GWh for the case of 5% ADR participation, small tank sizes and an upper bound of $90\,°C$ for the DHW tank. The mean DHW tank temperature duration curve (Figure 5b) reveals that the mean average temperature is about $51\,°C$ when the upper boundary is set to $60\,°C$ and $53\,°C$ when it set to $90\,°C$. Thus it is possible to conclude that it is not necessary to choose extreme design configurations to benefit of the flexibility of this kind of demand side technology[4]. On the contrary, the trend of relative operational costs shows that the maximum cost reduction is always highest for a total participation to the ADR program and it can be achieved for the configuration allowing more flexibility (highest upper bound temperature and big storage tank): it represents 0.7% of the total costs and corresponds to a saving of about 20 M€/year. Moving to the case with less flexibility (lower upper bound temperature and small storage), the maximum cost reduction drops to about 13 M€/year (Figure 4b). Eventually, from the point of view of the

[4]Current design practices are in line with the studied configurations.

buildings participating in the ADR program, it is possible to notice that the annual saving per dwelling is lower than in the previous cases (Figure 1b and Figure 4) and also the impact of the ADR penetration rate is less evident. The operational cost saving amounts to about 20 EUR per dwelling per year. Note however that in the case of flexibility in the DHW production, the shift in electricity consumption does not affect the perceived end-energy service. Indeed, when providing flexibility via ADR-subjected space heating, residents may be aware of (small) deviations of the temperature from their preferred set point. Domestic hot water will however always be available when requested, at the same temperature.

The aspect of the cost savings per building is of paramount importance in understanding the final customers' interest in ADR participation. In fact, while it is foreseeable that the electricity generation system can have benefits if the demand is flexible to its requests and constraints, it is less evident that the end consumer can sufficiently benefit in order to participate. The analysis performed in this study, even if based on some simplified assumptions, shows clearly that the customer could have a (sometimes limited) economic advantage, plus this advantage is reduced as more consumers adhere to the ADR program. The consumer thus favours a lower penetration rate of the ADR program, while on the contrary, the system as a whole benefits most from a high ADR participation rate. From both points of view, the use of the thermal flexibility of the building envelope introduces a bigger margin for profit than the flexibility in the DHW tank. Moreover the operational cost savings per dwelling should be compared with the investments required to upgrade a.o. the heating system control with a communication platform for the exchange of information with the electricity generation system [23, 24]. Note that at the demand side, the standard heating system installation, as conceived under design practices, is sufficient to exploit the inherent flexibility of these thermostatically controlled load.

Furthermore, it is worth stressing that the total energy demand for space heating is about 6 times bigger than the energy demand for warming the domestic hot water. At a 100% ADR penetration rate, the maximum energy demand is 6.92 TWh/year for space heating vs. 1.25 TWh/year for DHW. This puts the flexibility of the building thermal mass into perspective: its higher cost-saving potential is in part related to the higher energy consumption. In terms of installed power, there is no difference in the two analyzed cases, because the considered heating system consists of a heat pump providing both space heating and DHW.

In addition, it is also worth noting that the reduction of the operational costs when the two demand side technologies work together (Figure 1(right)) is slightly below the sum of the reductions of the operational costs when they work separately (Figure 4). This demonstrates that there is not a perfect superposition of the flexibility of different technologies. The more demand side technologies are participating in the ADR program, the lower the additional benefit of additional flexibility.

Finally, the potential for peak shifting is illustrated in Figure 6, which shows the peak electricity demand. In order to quantify the potential for peak shaving, two winter weeks with the highest electricity demand were considered, namely the second and third week of January. The integrated model was run with an additional constraint limiting the peak electricity demand. This constraint was lowered until the potential for peak shaving via load shifting with the considered demand side technology was exhausted. The resulting peak

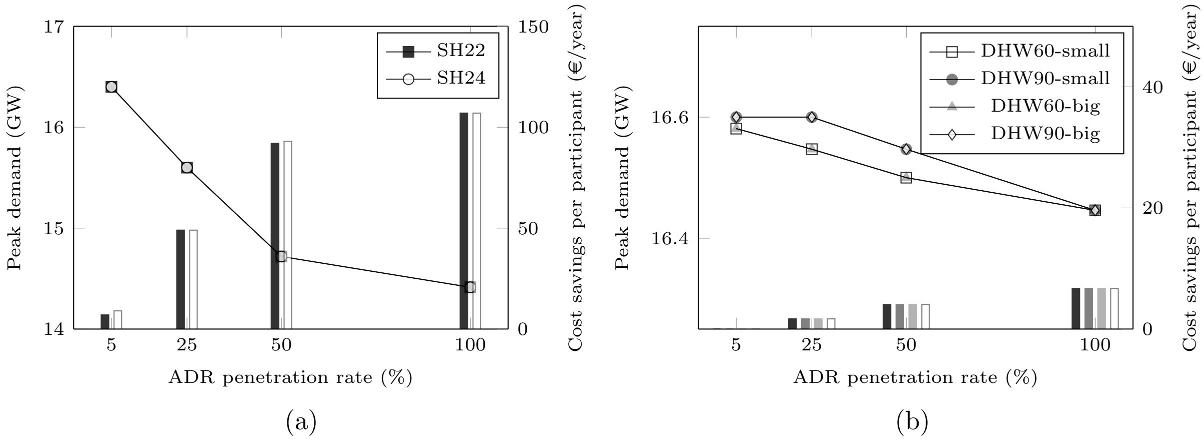


Figure 6: Peak power production trend and corresponding cost savings divided among participants when the flexibility of the building shell (Figure 6a) or the DHW tanks is exploited (Figure 6b. The lines correspond to th the peak electricity demand (left axis), the bars indicate the cost saving per participant (right axis). The colors of the bars and markers indicate the temperature set point and size of the demand side technology involved.

demand is shown in Figure 6. The flexibility in the building envelope allows a maximum peak shaving of about 2000 MW when the ADR participation is 100% for space heating, while the DHW production system allows a reduction of the peak electricity demand an order of magnitude lower (about 200 MW). Moreover, this peak demand reduction does not change significantly with the ADR penetration rate. This difference in peak shaving potential stems from the timing at which the heating of the building thermal mass and the DHW tank occurs. During cold months, high space heating demands coincide with the morning and evening peaks in the fixed electricity demand. Given the limited heat pump capacity, the loading of the DHW tanks is shifted towards the night, as the storage efficiency of these systems exceeds that of the building envelope. Hence, when peak shaving is needed, the potential of the DHW tank is low as its demand was already shifted from the typical peak electricity demand periods (morning and evening). Figure 6 also represents the behavior of the different configurations of the two demand side technologies with respect to the peak power production. It is evident that the typology of technology has an impact, but not its setting: the peak shaving potential does not vary significantly by changing the upper bound for the inside temperature or the upper bound for the DHW tank temperature and the tank volume.

The economic impact of peak shaving can be estimated by assuming an investment cost of 1250 EUR per kW installed for the peak production power plants [25]. A capacity decrease of 2000 MW would hence correspond to a deferred investment worth approx. 2500 M€. In order to make a comparison with the benefits produced by the reduction of operational costs, the latter value is shared among the participants annually, assuming a plant life time

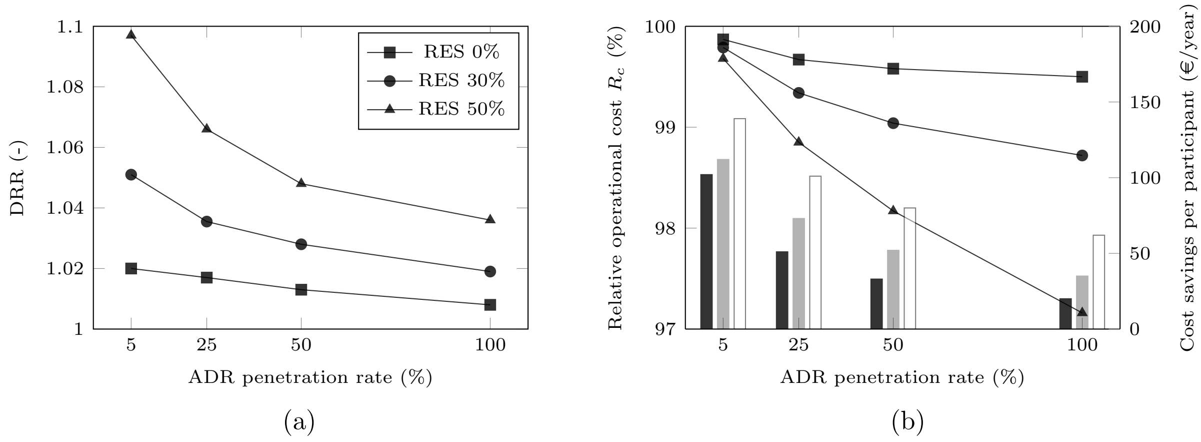


Figure 7: DRR (left) and relative cost difference (right) for different shares of RES and ADR participation.

of 25 years[5]. The savings per participant (Figure 6) show an opposite trend compared to the operational cost savings per participant (Figure 4a). The total saving per participant (operational plus investment costs savings) changes slightly for different ADR participation and it is a little higher for the maximum adherence to the ADR program, confirming the importance of the reduction of investment costs in a complete assessment of the benefits of ADR for the overall energy power system. Note that the exact value of these cost savings is highly dependent on the assumed investment cost and discount rate.

3.3. Influence of the RES share

As one of the main purposes of introducing ADR programs lays in the possibility of better matching the demand with a fluctuating renewable electricity generation due to renewable sources, the sensitivity towards the RES share is studied in this section (Case 'RES share', Table 1). Figure 7 shows the DRR and the relative operational costs, R_c, when renewable energy sources cover 0%, 30% or 50% of the total electricity demand. For a higher RES penetration in the generation mix, more load shifting is requested of the dwellings involved in the ADR program (i.e. higher DRR). This is also accompanied by higher annual operational benefits, reflected by the higher cost reduction, both in relative and absolute value. For the cases with 100% ADR penetration, the absolute value of costs saving for the system was estimated at 20 M€/year over a total production cost of about 4000 M€/year for a RES share of 0%, at 35.5 M€/year over a total production cost of about 2700 M€/year for a RES share of 30% and at 62.7 M€/year over a total production cost of about 2200 M€/year for a RES share of 50%.

This is also translated in increased savings/incentives per participant (Figure 7b). When more RES-based generation is available, it is evident that more flexibility in demand side technologies is more relevant. For example, for the case with only building thermal mass

[5]Note that for this estimate, we did not apply any discounting.

Table 2: Curtailment of RES-based electricity generation for a 30% RES penetration, provided by wind or solar energy. The curtailment levels are split based on the time of year (heating season and rest of the year). In terms of ADR penetration, two cases are shown (0% and 100%). DHW indicates the situation in which only the flexibility of the DHW tanks is exploited (small tanks, max. temperature at $60°C$), SH corresponds to the case in which only the space heating system is ADR-adherent (maximum day-zone temperature at $22°C$).

	100 % Wind				100 % PV			
	Heating season		Rest of year		Heating season		Rest of year	
ADR penetration rate (%)	0	100	0	100	0	100	0	100
DHW(GWh)	84	63	34	31	2938	2802	3018	2914
SH(GWh)	84	51	34	34	2938	2011	3018	3018

flexibility and a 50% share of RES, the maximum system cost saving goes from 52.7 M€/year up to 56 M€/year by increasing the upper bound from $22\,°C$ to $24\,°C$. This is in contrast in the previous section with a 30% share of RES, where there was almost no difference between the two cases.

A further evaluation was carried out to investigate the influence of the composition of the renewable sources mix between solar and wind power in two extreme cases (100% PV and 0% wind or 0% PV and 100% wind). For the case with only building flexibility and 30% RES share, the PV dominated scenario produces a DRR up to 8% (for 5% ADR) and an operational costs reduction (for 100% ADR) up to 62 M€/year. In the wind dominated scenario, a DRR up to 3% (for 5% ADR) and an operational costs reduction of 15 M€/year (for 100% ADR) is observed. Table 2 shows the cut in RES curtailment by shifting only the space heating energy demand or only the domestic hot water energy demand. The DHW tank can reduce curtailment throughout the year, while for space heating, this is limited to the heating season. The reduction in curtailment is lower compared to the space heating, but note that the DHW tank also represents a lower energy demand. These results further highlight that a massive PV deployment gives higher incentives for ADR than a massive wind deployment. This is due to lower capacity factor of solar power: more capacity is to be installed to achieve the same RES share in the final energy demand. As a consequence, higher RES-based electricity generation peaks are to be expected, which are often to be curtailed.

Figure 14 has been re-moved. Seems super-fluous.

4. Conclusion

This paper analyzes the role of the ADR penetration on the performance of the integrated demand-supply electricity system. The demand side technologies considered are electric heating systems coupled with thermal energy storage. The analysis makes an attempt on evaluating the flexibility of thermal inertia in buildings, in terms of energy consumption and operational costs. The main conclusions are the following.

Firstly, the increasing of ADR penetration rate increases the reduction of operational costs, but on the other hand decreases the savings per participant since less load shifting per dwelling is necessary. This results also in a reduction of the demand response ratio. Hence, as more buildings participate in ADR, the less these see an altering in their electricity demand. Secondly, ADR can be put into practice thanks to the considered demand side technologies without asking for particular design constraints or configurations different to the standard operational range of such systems. Hence the increasing of the upper temperature bounds or a doubling of the DHW tank size, show relatively little extra value. The flexibility due to the building thermal mass involves a higher energy demand and is hence more attractive for ADR purposes, even if its availability is only present during the heating season. Additionally, this demand contributes the most to the winter peak electricity demand and is thus also the most attractive for peak shaving. Thirdly, the higher the renewable sources production, the higher the benefits that can be attained by the ADR application.

Finally, this paper again demonstrates the strict interaction between the demand and the supply side: the behavior of the flexible electric heating systems is not only dependent on the consumers themselves, but also on the boundary conditions under which they operate, such as the RES share in the system and the behavior of the other consumers. Thus, in order to assess the added value and effects of ADR, it is necessary to take both the demand and supply of the electricity generation into account, WtextcolorKBfor example through integrated modeling approaches.

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