Photovoltaics and Heat Pumps – Limitations of Local Pricing Mechanisms

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Abstract

With the increasing amount of volatile infeed from renewable energy sources the need for flexibility becomes more and more urgent. This holds especially for the distribution grids where critical load situations caused by high local renewable infeed occur increasingly often. Therefore, demand side management with broad participation of households has been proposed as one cornerstone for a future sustainable energy system. Local prices may contribute substantially to enable a smart behaviour of grid users by providing appropriate incentives. Although the benefits of both demand side management and local prices seem evident in theory, practicalities have to be considered when it comes to assessing their effectiveness. Notably individual restrictions for different kinds of grid users have to be regarded in detail. Eventually, the potential contribution of local pricing to a secure and efficient energy system may be called into question.

In this paper, a typical rural low voltage grid is analysed having local electricity generation from PV systems and typical household consumption. In addition, a high penetration of heat pumps is supposed as well as the implementation of a framework of local prices. With households heated by electric heat pumps a potentially flexible consumer type is implemented in detail. Thus, a model of a possible future rural low voltage system is implemented and used to assess the limitations of local pricing mechanisms – firstly, by a sequential deduction of the possibly leveraged potential of the local market mechanism under existing technical constraints and, secondly, by a scenario analysis of the allocation of economic benefits. Results show that even with given local incentives the consumption adjustment towards an efficient grid usage cannot be realized frequently as comfort and system needs have priority. I.e. due to limited complementarity of heat pump consumption and photovoltaic infeed patterns expected operational system cost reduction is low – especially in comparison to required investments in smart systems. Hence, the example disproves any generalized claims about the efficiency of local pricing - yet obviously it does not prove that local pricing is of no worth in general. As second main result, stylized policy choices are analysed. Thus, it is demonstrated how the benefits of local pricing mechanisms can be distributed to the market participants and which are the difficulties that policy makers will have to face. Ultimately, for the present case study, it is not possible to set sufficient investment incentives for the installation of flexibility measures for heat

pumps without either causing disadvantages to renewables-based electricity generators or without receiving additional regulatory payments from the overarching system.

Thereby, the paper contributes to the existing literature by analysing a novel pricing mechanism and, more importantly, demonstrating the effects of these pricing mechanisms on the system costs and the economic figures of the market participants. As main result, it can be seen that practicalities play an important role and must be taken into account when considering the implementation of local pricing mechanisms. Furthermore, policy makers have to pay attention to the redistributive effects as they might be substantial even though the costs savings of the overall system will not necessarily be meaningful.

Keywords: Integration of Renewables, Distribution Grid, Local Pricing, Agent-Based Simulation, Demand Side Management, Heat Pump.

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Abbreviations

amb (index)	ambient
C	capacity constraint
c	grid charges
c_W	specific heat capacity of water
$C_{z/fh}$	absolute heat capacity of the heating zone / floor heating
$CAPEX_{flex,annualised}$	capital expenditures of additional flexibility measures (annualised)
CF	cash flow
COP	coefficient of performance
D	discount
DSM	demand side management
DSO ($also\ index$)	distribution grid operator
$glob$ ($index$)	global (simplified for the non-local pricing mechanism)
E	electrical energy (consumed/ generated per year)
ECC	end consumer charge
eoc ($index$)	end of congestion
eoo ($index$)	end of operation
fh **(index)**	floor heating
HGL ($also\ index$)	higher grid level
HH	households
hp ($index$)	one individual heat pump
HP ($also\ index$)	heat pump (as index: group of heat pumps within the system)
H_{TV}	design heat load of the building (accounting for transmission and ventilation losses)
LVG	low voltage grid
loc ($index$)	local
LV	low voltage
max ($index$)	maximum (possible)
min ($also\ index$)	minimum
MP	market premium
$OPEX_{flex}$	operational expenditures of additional flexibility measures
p	price (with index “comp” also used for the compensation rate for being curtailed)
P	electrical power (consumed or supplied)
$\widetilde{P}$	curtailed power
PV ($also\ index$)	photovoltaics
RE ($also\ index$)	renewable energy
rem ($index$)	remaining, i.e. the part of electricity not generated and consumed locally
RES	renewable energy sources
ρ_w	density of water
SC	system costs
soc ($index$)	start of congestion
st ($index$)	storage
SYS ($index$)	system (all elements within the system boundary as shown in figure 3)
t ($index$)	time step
τ_{summer}	non-heating period
T	temperature
T_{design}	design ambient temperature as per DIN 12831
TF ($index$)	transformer
tol ($index$)	tolerable
tot ($index$)	total
U	markup
V	volume
$VARMA$	vector autoregressive moving average
WSM ($index$)	wholesale market
z ($index$)	heating zone

1 Introduction

During the last decade, renewable energy (RE) found its way into the electricity generation portfolio. In 2014, the gross electricity generation from wind and solar energy sources (non-dispatchable renewables-based technologies) in Germany amounted to approx. 91 TWh representing 14.7 % of the total gross electricity generation BDEW (2015). The increasing capacities of RE installations in Germany have led to highly fluctuating electricity infeed occurring independently from demand. Such circumstances have entailed the necessity of repeated curtailment of RE generators. Curtailment being caused by the distribution grid has increased substantially in recent years (BNetzA and BKartA (2015)). In 2014, compensations of approx. 42.1 million € were paid and a RE generation of 659.1 GWh was prevented due to remedial measures having its cause in the German distribution grids. The reduction of RE generation with causation of the German transmission grid is still higher (921.4 GWh), but, in terms of compensation (40.6 million €), the distribution grid is already more significant.

One possibility to face this challenge is the grid extension according to the traditional N-1-criterium. In order to avoid curtailment dena (2012) states that up to 42.5 billion € have to be invested into the German distribution grids by 2030, which includes the extension of electricity circuits by up to 192,900 km and installation of additional transformation capacities of 93,290 MVA.

If being the only measure such a principle would lead to a grid designed for extreme situations, which causes, on the economical side, the need for high investments and, on the technical side, a low number of annual full-load hours of grid devices. In combination, this can lead to an inefficient utilization of resources which is not economically-reasonable. This is probably the reason why the consideration of curtailment of up to 3 % of the yearly generation in the grid planning is currently foreseen (CDU, CSU, SPD (2013), E-Bridge, IAEW, Offis (2014) and BMWi (2015)).

As solution for the near future – especially with better technical systems and automated processes – the use of demand side flexibilities has been proposed in order to avoid curtailment. When technical conditions are provided and shifting of energy consumption is possible without loss of comfort, then, demand side management (DSM) may help to release congested grid situations. The potential for peak load shaving through DSM measures is analysed, inter alia, in Veldman et al. (2013), Papadaskalopoulos and Strbac (2013) and Papadaskalopoulos et al. (2013).

Yet, appropriate incentives for shifting load at certain hours are required. Traditionally, retail prices do not provide these incentives. Firstly, because commonly retail prices do not reflect real-time wholesale market prices. Secondly, even if this was the case, wholesale market prices do not reflect local grid constraints / local congestion. The use of local price signals has been proposed as a means to align demand and supply at higher spatial resolution. Locational marginal pricing for distribution grids is similar to concepts for the transmission grid level (Hogan (1992), Schweppe et al. (2000)). This concept and further alternative approaches are discussed in Brandstätt et al. (2011). Trepper et al. (2013b) present a conceptual approach of congestion-oriented grid charges for European-style, non-nodal markets. They explain various benefits of a system that provides local incentives when the grid is congested due to extreme local infeed. Particularly, curtailment of RE generation is said to be avoided and therewith compensation payments for not delivered electricity are prevented. Furthermore, the increased use of electricity generated close-by is the intention of congestion-oriented grid charges. Thus, utilisation and congestion of overlaying grid levels shall be reduced. Yet, electricity losses with transmission are rather low, and therefore differing local incentives are efficient only in case of congested grid capacity. As the national wholesale market price does not always provide sufficient signals to trigger RE generation according to the needs of the distribution grid (cf. Picciariello et al. (2015), Velik and Nicolay (2014)) and as the occurrences of congestion (in terms of local and timely variance) depend on the situation of the distribution grid, the adequacy of the price signal can only be reached in a local market. For the purpose of this paper, congestion-oriented grid charges in combination with the underlying wholesale market price are called local prices. The organisational issues of the bidding process (as described in Trepper et al. (2013a) and Trepper et al. (2013b)) are not taken into focus. However, the results of this paper can be understood as those of an efficient organisation.

Certainly, several regulatory, market and technology barriers which have to be removed to implement dynamic pricing concepts have already been identified (e.g. Shen et al. (2014), BMWi (2014)). Other critical points are the consumers' acceptance of such schemes (e.g. Kowalska-Pyzalska et al. (2014), Leonard and Decker (2012), Dütschke and Paetz (2013), Brandstätt et al. (2011)). The present work uses the hypothesis that these barriers can be overcome as long as the socio-economic welfare effect is sufficiently advantageous. Instead, the focus of this work is laid on the evaluation of the actual realization of these theoretical benefits of local pricing mechanisms. On the one hand, financial benefits also need to be apparent to potential market participants in order to accept a local pricing regime. In any case, loss of comfort must be avoided, which poses technical restrictions to the involved equipment.

Heat pumps (HPs), for example, have a great flexibility potential within the residential sector (as it is analysed e.g. in Di Giorgio and Pimpinella (2012), Hedegaard and Balyk (2013), Waite and Modi (2014), Papaefthymiou et al. (2012), Prognos AG, Ecofys Germany GmbH (2011), Mueller et al. (2014), ETG (2015)). Firstly, HPs feature a high electrical power consumption compared to the ordinary household loads as environmental thermal energy is made usable through a thermodynamic process which is driven by an electrically-powered compressor. Moreover, a certain amount of flexibility is readily available by the thermal inertia of buildings. That is, heat supply and HP operation is decoupled to a certain extent. Additionally, a storage tank can serve as expanded thermal capacity which allows a more flexible operation of the HP as times of storage tank charging and heat supply to the building may differ. E.g. Schmidt et al. (2010), Verhelst et al. (2012) and Vanhoudt et al. (2014) have demonstrated that air-water HPs provide flexibility in order to adjust consumption towards external objectives.

However, one has to consider that additional flexibility (e.g. through installation of storage tanks including additional subsidiary equipment for HPs) has its costs and a remuneration has to be provided by the incentivising framework. In turn, on the supply side, claims will be made that RE generators should not have disadvantages in regional markets with local prices over a national wholesale market (cf. Brandstätt et al. (2011)). Therefore, the possible allocation of operational system cost savings to the different market participants is an important aspect.

In summary, before planning an incentivising concept for local adjustment of infeed and consumption - at least - two tasks should be carried out:

a) an assessment of actually achievable advantages of the local pricing regime for the regarded system, and
b) an analysis of the consequences for each market participant and the resulting long-term incentives.

In this paper, an energy system is presented that includes the above mentioned concept of local prices which provide short-term incentives for price responsive HPs. An agent-based simulation shows the interplay of the pricing mechanism, local RE generators and flexible and inflexible consumers within a structurally-congested distribution grid. Modelling each agent by means of individual and detailed sub-models provides the necessary precision for such analysis. The advantageousness of the local pricing mechanism is analysed with the focus on both the system benefits and the impacts for the individual participants. For the latter analysis, scenarios are evaluated which can be seen as extreme positions of regulatory setups illustrating how policy makers can influence the benefits of the participants in local markets. As a test case a low voltage grid (LVG) in a rural environment is chosen which is based on an existing grid sample in Germany. Considered are, among others, photovoltaic (PV) systems and households with HPs. Their penetration has been set according to forecast values (taken from the literature) while the grid's technical features remain unchanged from today's status. Thus, the concept of local pricing is analysed in a situation as it may arise in the future distribution grid.

This paper is structured as follows: Section 2 describes how the technical features and supposed market mechanism are modelled. Section 3 continues with the demonstration of the methodology for the assessment of the potential of such market mechanisms. It is followed by the introduction of a test case including policy scenarios which are made subject to assessment (section 4) and by the corresponding results (section 5). Finally, the relevant conclusions are drawn in section 6.

2 Modelling Approach

2.1 General Model

The present study links several sub-models which represent the behaviour and features of the grid and the grid users. They are coordinated by a market clearing entity which is an individual sub-model itself (also referred to as market agent) and which includes a local pricing mechanism. It uses information about the operational status of the grid to calculate local market prices with the aim of incentivising demand shifting in a way that congestion is avoided. Thus, the following sub-section starts with the explanation of the local pricing mechanism.

The resulting local prices impact the flexible consumers' operation decisions. These will consume electricity if prices are below a consumer and situation specific threshold derived from the respective cost minimisation strategy under consideration of technical constraints. This strategy is discussed further in section 2.3.

All sub-models are implemented in a Java framework which is discussed in section 2.4.

The simulation notably allows to derive the local prices, hours of congestion, avoided hours of congestion due to DSM, changes in generation and consumption, savings and revenue changes of consumers and generators, respectively, avoided curtailment, etc. All results are available in hourly resolution.

The algorithms for obtaining the above results are described in detail in Raasch and Weber (2016) and Felten and Weber (2016) and, therefore, are only illustrated briefly in the present document. Here, the focus is laid on the aggregate results of the interplay of all sub-models.

2.2 Incentivising Framework: Local Pricing Mechanism

Typically, wholesale market prices reflect the supply and demand situation on a national level and at high timely resolution (usually hourly). However, due to regional heterogeneity of the power system (especially on the generation side), the price formation process on a national level frequently results in grid constraints at local level (cf. section 1). If using prices as prior means to improve system balance in affected regions the respective local equilibrium prices must diverge from the national wholesale market price. Thus, a concept of local pricing, which indicates local temporary scarcity of grid capacity when it is apparent, is implemented.

As will be explained below, generators will chose to feed in electricity once they are reimbursed at an appropriate price. Consumers will decide to consume if prices are acceptably low. Based on the initial bids and asks on the local market, which are based on the (national) wholesale market price, the balance of anticipated local infeed and load is evaluated for each hour and is compared to the available grid capacity. If (and only if) the balance exceeds the grid capacities, an additional markup or, respectively, a discount to the wholesale market price is computed. The local clearance price is achieved in real-time by an iterative process during which local generators and flexible consumers adjust their bids and asks. Hence, the main objective of the process is the most efficient use of grid capacities. The algorithm for determining the local price is shown in figure 1.

Thus, appropriate incentives for reducing curtailment are computed and applied to the market participants. The corresponding local price $p_{loc,t}$ can be formulated as follows:

$$p_{loc,t} = \begin{cases} p_{WSM,t} + U_{loc,t} & if\ residual\ load\ induces\ grid\ constraint\ violation \\ p_{WSM,t} - D_{loc,t} & if\ residual\ infeed\ induces\ grid\ constraint\ violation \\ p_{WSM,t} & otherwise \end{cases} \tag{1}$$

Here, $p_{WSM,t}$ represents the wholesale market price at time t, $U_{loc,t}$ a suitable markup and $D_{loc,t}$ a suitable discount. Thus, signals for additional load or reduced RE infeed are provided and a behaviour which is oriented towards an optimised grid utilization is induced. Further details on the pricing mechanism and its implementation are given in Raasch et al. (2014) and Raasch and Weber (2016).

These local prices provide an incentive to RE generators to turn off whenever the sum of the local price and a possibly paid “market premium” becomes negative. The price responsive behaviour of flexible consumers is discussed in more detail in the following section.

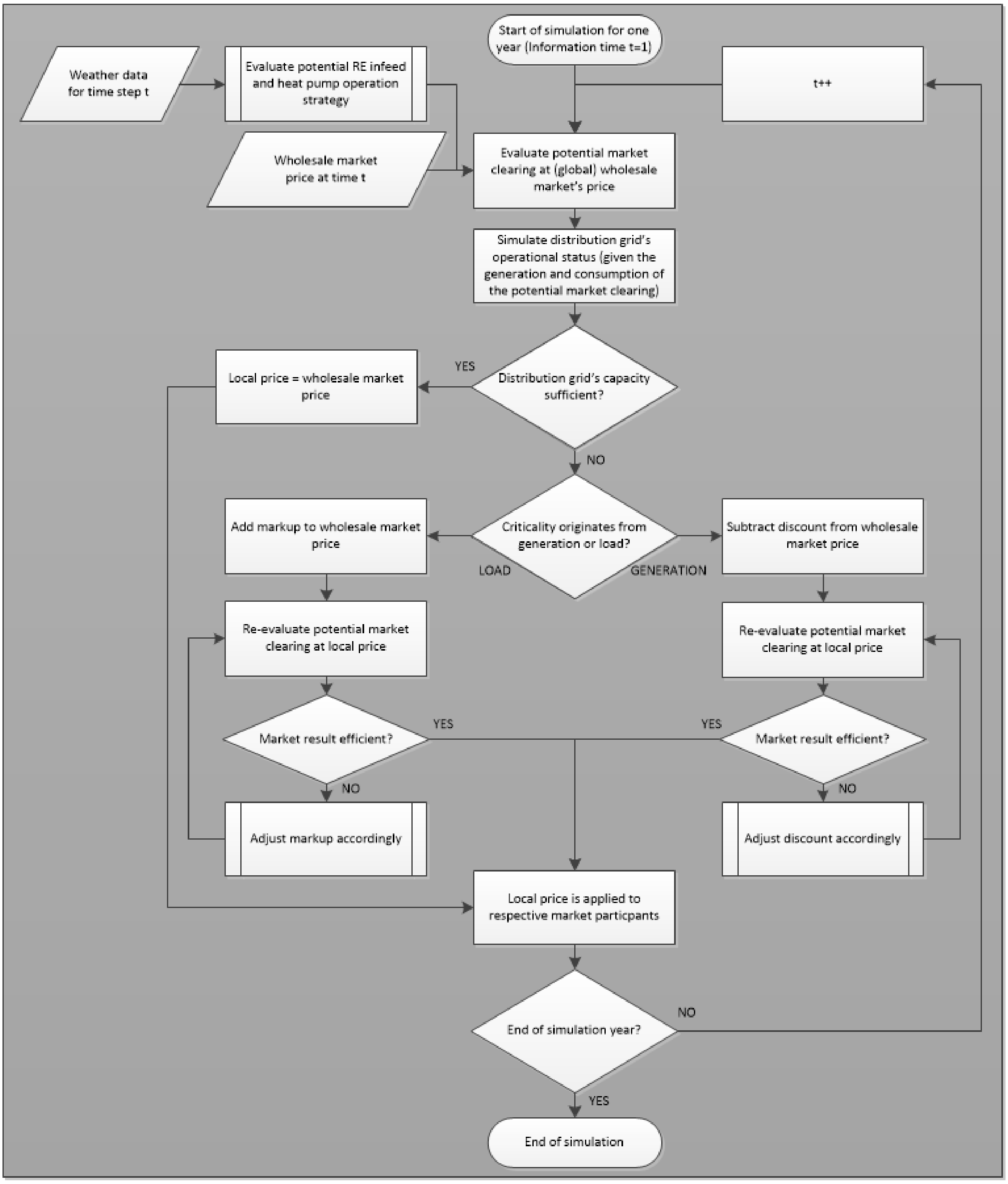


Figure 1: Flow chart of the used local pricing algorithm

2.3 Flexible Consumption: HP System and Control Methods

As HPs are frequently-referred to as one of the most promising electric devices for DSM of private households, the HP systems are modelled in detail and its operation is simulated in the context of the described local pricing concept. A thermal storage tank belonging to each heating system provides additional flexibility. Among other differences to further models simulating HP operation strategies (cf. Schmidt et al. (2010) and Verhelst et al. (2012)), the most relevant is the integration of a price forecast algorithm enabling the HPs to perform a rolling planning of its cost-optimised operation. Thereby, the sub-model can be used in a modelling framework which determines local prices endogenously.

The used heating model has been developed by applying the first law of thermodynamics for each sub-system of the building system (including storage) and dynamics are represented by a set of linear differential equations. The technical constraints such as maximum and minimum storage temperature and the set value of the zone temperature need to be fulfilled by the DSM device. A model-predictive cost optimising control is implemented which uses two specific vector autoregressive moving average processes of first order (VARMA(1,1)) to forecast local prices and ambient temperature, respectively. By establishing the relation between forecast ambient temperature, anticipated supply temperature and HP efficiency (coefficient of performance (COP)), and combining it with the forecast of the local prices, the forecast price of heat is calculated. This is used to predict the most cost-efficient times of HP operation. Considering the heat demand restriction (which always needs to be fulfilled), this leads to a threshold of the local price below which the HP's operation is forecast to be optimal. The forecasting and decision processes are executed on an hourly basis with a 24 hour look-ahead horizon. The algorithm is explained in more detail in Felten et al. (2014) and Felten and Weber (2016). Figure 2 provides a schematic flow chart.

In figure 2, the hours within the look-ahead horizon that are highlighted are the ones during which HP operation is expected to be most cost-efficient given the information available at time t. The optimal strategy identified for the current hour (hour 0) is put into practice whereas the further planned operation steps are subject to revision as new information becomes available. Hence, the only immediate consequence is that, at hour 0, the HP will remain switched off (in the used example).

It is noteworthy that the operation of the floor heating is independent from HP operation as the floor heating is supplied by the thermal storage tank. Thus, by providing local prices an orientation of HP operation towards local supply and efficient grid utilization is generally enabled. But, in each operation mode, basic requirements as comfortable zone temperatures may not be jeopardized.

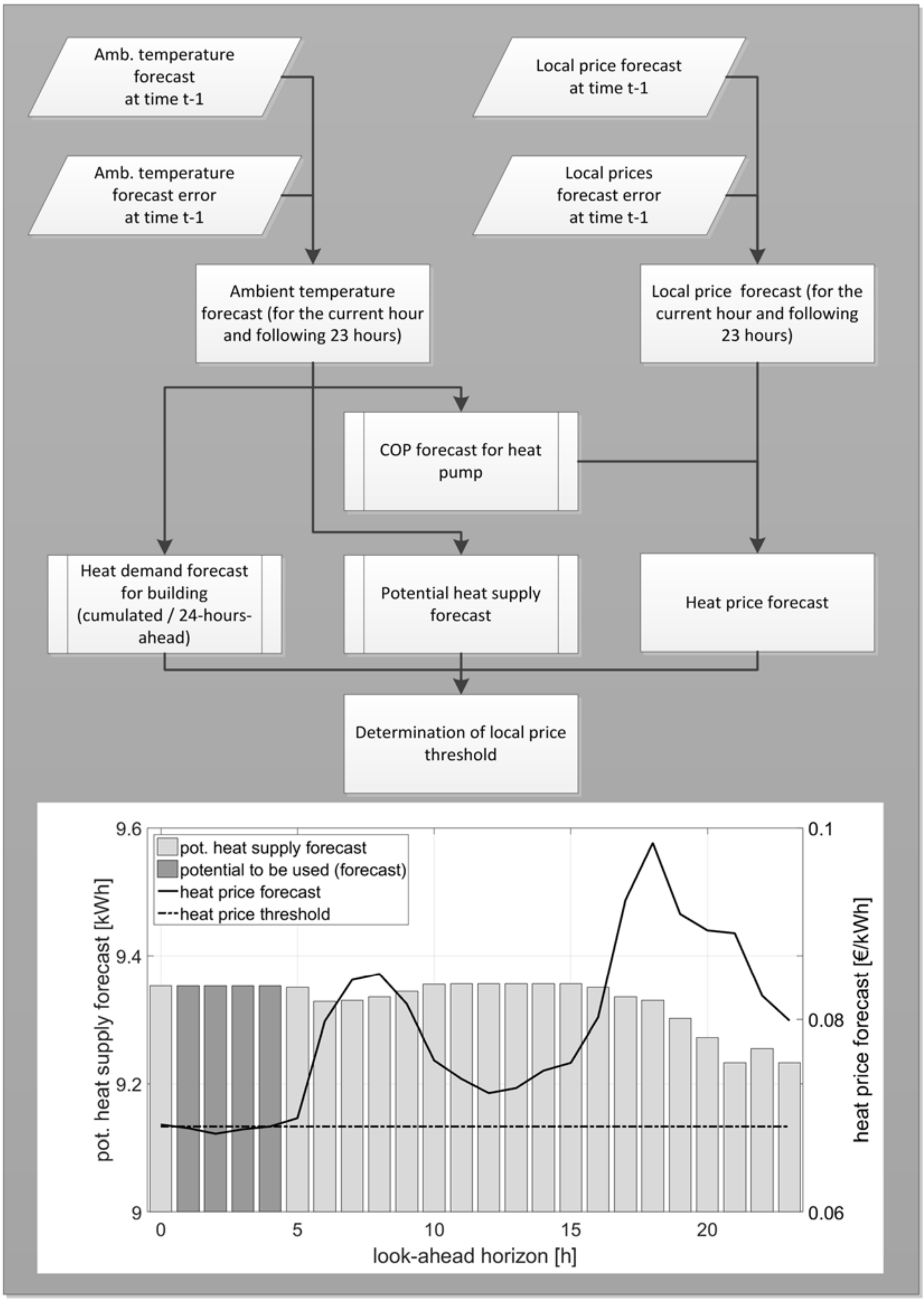


Figure 2: Illustration of the forecasting algorithm and its main results for one exemplary hour

2.4 Model Framework: Agent-Based Simulation

The heterogeneous behaviour of market participants is simulated within an agent-based model which is implemented in the Java framework Jade. This simulation is based on a multi-agent system presented in Kays et al. (2013). Overload situations of individual lines and grid devices can be identified (or anticipated) and notified to the market agent. Local generators can be modelled as PV systems and wind farms. The consumption is given by typical household loads as well as by more sophisticated HPs. Representing each grid user by an own agent enables a highly detailed simulation, which is important as specific technical characteristics (e.g. orientation of solar panels, capacities of generators, building characteristics, HP capacity and thermal storage size), local environmental conditions (e.g. irradiation including shading, ambient temperature, etc.) and individual preferences (set zone temperatures, household demand profiles) can vary for each agent. This leads to individual decisions of each generator and consumer which provides a more adequate depiction of the market mechanisms.

3 Methodology of Assessment

3.1 Assessment of Electricity Flows

The present study supposes a distribution grid which has two types of loads: The regular household load and the HP load. The methodology of evaluation is capable of capturing further consumer types, but the test case has been limited to these two for the sake of a more concise analysis. The same applies for electricity generators of which only PV installations are used as typical example. Thus, figure 3 illustrates the groups of considered consumers and generators, the system boundary and physical and financial flows between the different participants and the overarching system.

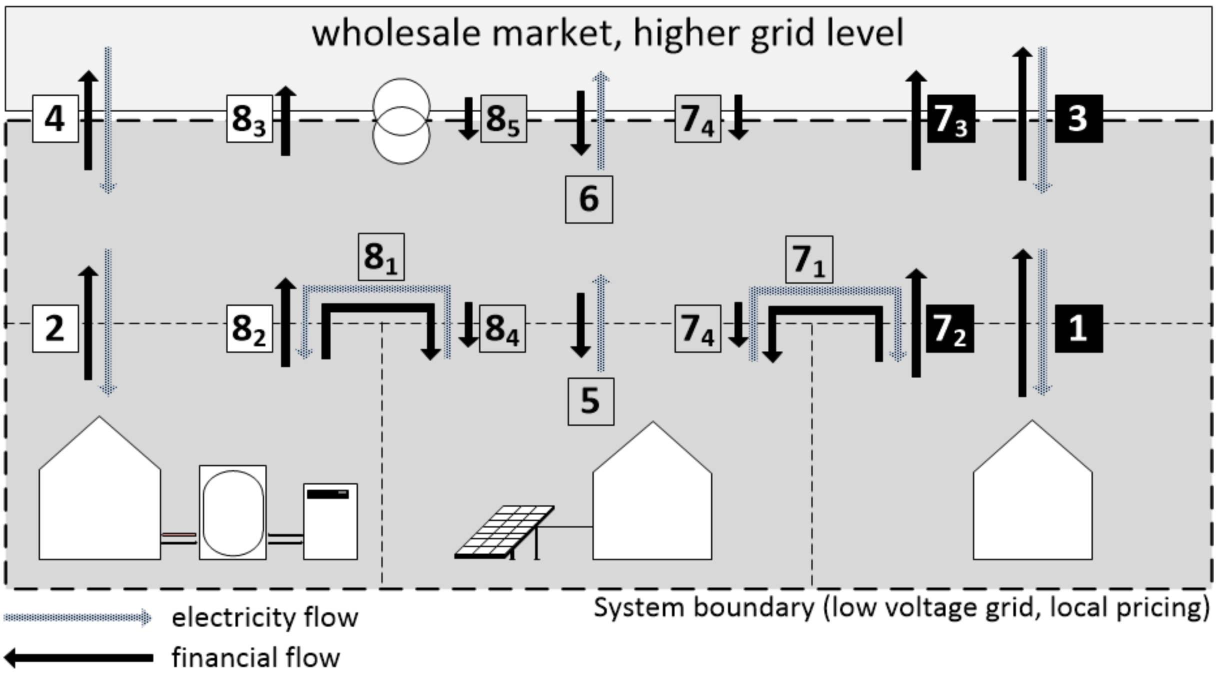


Figure 3: Schematic of the regarded system, its electricity flows and corresponding financial flows

In figure 3, each physical flow (i.e. electricity transmission) is understood to cause a financial flow. Some electricity remains within the system boundary: I.e. electricity flows which originate from local RE generators (index "RE") are consumed locally by households (index "HH") and / or heat pumps (index "HP") at the same time t. The denotation of the electricity flows (which are assumed to be constant during each time step) and its reference in figure 3 (in parentheses) are $P_{HH,loc,t}$ (7_1), $P_{HP,loc,t}(8_1)$ and $P_{RE,loc,t}$ $(7_1 + 8_1)$. The relation between the three values is given as follows:

$$P_{HH,loc,t} + P_{HP,loc,t} = P_{RE,loc,t} \tag{2}$$

The remaining demand needs to be procured from the higher grid level (HGL) and is symbolized by $P_{HH,rem,t}$ (figure 3: 1) and $P_{HP,rem,t}$ (figure 3: 2), respectively.

In order to simplify the grid constraints, in the subsequent sections, only simple power transfer limitations of the following form are discussed.

$$P_{RE,rem,t} \leq C \tag{3}$$

This limit may be imposed by the capacity of a transformer or by the maximum current on a line. Equation 3 refers to the supply side, i.e. surplus of power (symbolized as $P_{RE,rem,t}$ (figure 3: 5)) is exported to the HGL to the extent technically possible. The analogous constraint applies to the demand side.

3.2 Assessment of Technical Potential

As the main objective of local pricing mechanisms is the reduction of curtailment this section describes how curtailment can be quantified and how the potential for stepwise deduction of curtailment can be assessed. Without loss of generality, the methodology of assessment is illustrated for a structurally congested grid in which only situations of a surplus of RE infeed occur and the bottleneck is the transformer capacity C_{TF}. Each step is indicated by a new literal which serves as reference in section 5.2.

a) If the local demand plus transformer capacity is smaller than the maximum possible RE generation $P_{RE,max,t}$, this leads to curtailment of RE generators. If using C_{TF} efficiently, the curtailed power $\tilde{P}_{RE,t}$ can be expressed as follows:

$$\tilde{P}_{RE,t} = P_{RE,max,t} - C_{TF} - P_{HH,loc,t} - P_{HP,loc,t} \tag{4}$$

b) In above equation, it must be considered that HPs are typically taken out of operation for the summer period. Thus, there is a technical constraint:

$$P_{HP,loc,t} = 0 \;\; \forall\, t \in \; \tau_{summer} \tag{5}$$

c) Usually, HP layout is based on the design heat load of the respective building (DIN EN 12831 (2003)). Thus, the nominal HP capacity is oriented towards the building characteristics (cf. Novelan (2013)) with the goal of achieving an appropriate amount of monovalent operation hours during the year (reduced use of supplementary heating element). A typical HP control uses a characteristic map which aims at achieving the highest COP. This characteristic map is HP specific and its input parameters are the ambient temperature and the supply temperature (cf. Panasonic Deutschland (2014a)). These parameters are often interrelated by a so-called heating curve (Schmidt et al. (2010) and Verhelst et al. (2012)), which – in essence – is a consequence of limited floor heating surface area and the thermal inertia of the building. I.e. in order to provide sufficient heat to the heating zone during days of low ambient temperature T_{amb} the supply temperature T_{supply} needs to be raised. Such a heating curve is shown in figure 4a.

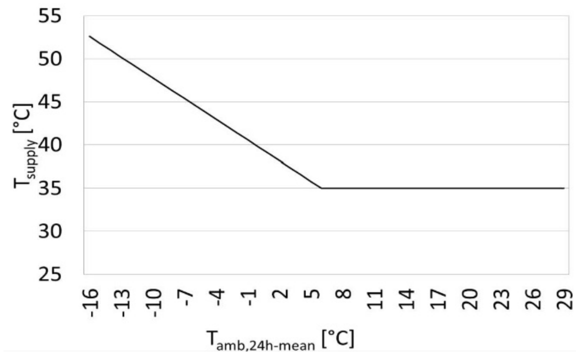


Figure 4a: Illustration of a typical heating curve (supply temperature as a function of 24-hour-mean ambient temperature)

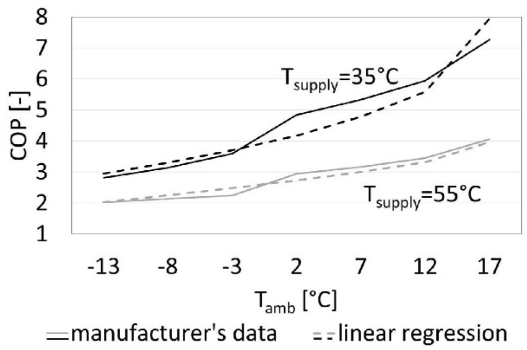


Figure 4b: COP of the simulated HP as a function of the ambient temperature given for two supply temperature settings (on basis of Panasonic Deutschland (2014a))

The foregoing technical interdependencies are implemented in the agent-based simulation in more detail and are used for the actual operation mode as well as for the model-predictive control strategy of the HP. For the purpose of the ex-post assessment, a simplified relationship to calculate the maximum possible electricity consumption of the heat pumps $P_{HP,max,t}$ is used (shown in figure 5).

d) Although additional flexibility is made available by thermal storages it is not infinite. If assuming that the HP was controlled in a congestion-optimal way (i.e. the thermal storage at the first hour of grid congestion was at its minimum temperature $T_{st,min}$ and the heating zone temperature of the building was at its minimum allowable

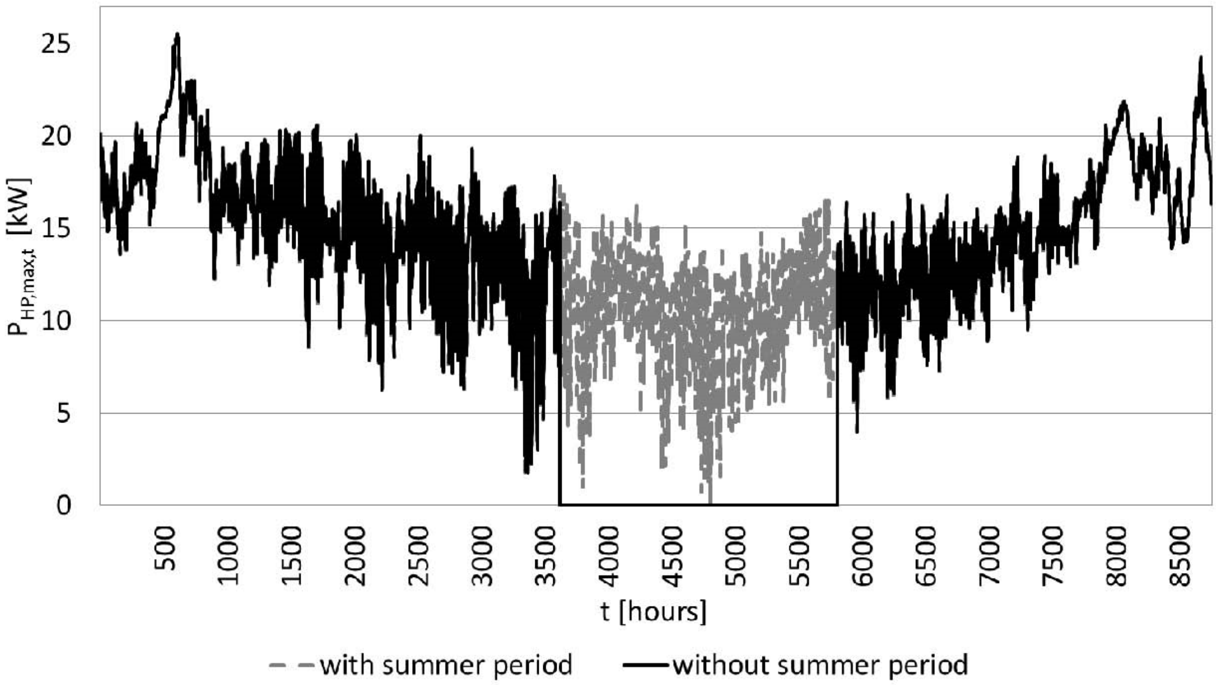


Figure 5: Maximum possible electricity consumption by HPs over the year (considering supply temperature settings according to technical operation criteria)

temperature $T_{comf} - \Delta T_{tol}$) the HP can only remain turned on until the thermal storage reaches its maximum temperature $T_{st,max}$) following HP operation restriction must be fulfilled.

$$c_w \, \rho_w V_{st}\left(T_{st,max} - T_{st,min}\right) + 2C_z \Delta T_{tol} + C_{fh} \Delta T_{f,max} \; + \sum_{t=t_{soc}}^{t_{eoo}} H_{TV} \frac{T_{z,t} - T_{amb,t}}{\Delta T_{design}} \Delta t \geq \sum_{t=t_{soc}}^{t_{eoo}} P_{hp,th,t} \, COP_t \Delta t \qquad (6)$$

Here, c_w is the specific heat capacity of water, ρ_w its density. V_{st} is the storage volume (filled with water), C_z the absolute heat capacity of the heating zone of the building, ΔT_{tol} the temperature tolerance by which the heating zone temperature may diverge from its comfort temperature, C_{fh} the absolute heat capacity of the floor heating, $\Delta T_{f,max}$ the maximum temperature increase of the floor heating during hours of congestion, H_{TV} the design heat load of the building, $T_{z,t}$ the zone temperature of the building, $T_{amb,t}$ the ambient temperature, ΔT_{design} the design temperature difference, $\Delta\, t$ the duration of the time step (here: 1 hour). t_{soc} indicates the time step of the start of congestion. t_{eoo} is the time step at which the HP operation must / can end. The HP operation must end when the maximum storage temperature is reached. It can end – considering a curtailment minimization logic – when no congestion is apparent anymore (indicated by the time step t_{eoc}).

$$t_{eoo} = min\{\ t(T_{st,max}), t_{eoc}\ \} \tag{7}$$

e) A forecasting algorithm will always have some degree of inaccuracy. Furthermore, achieving the optimal starting temperature as described under literal d may not be possible if periods of congestion are interrupted shortly and the building's heat demand meanwhile is not high enough to lower the minimum storage temperature. Thus, thermal storage temperature will not always be at $T_{St,min}$ at the first hour of congestion. This implies a further reduction of flexibility. The remainder of the actually achieved curtailment reduction and the reduction potential under literal d can be assigned to these effects. This is in line with the scenarios of the forecasting algorithm shown in Felten et al. (2014).

f) Finally, there is some amount of curtailment which HPs with an ordinary control (according to technical criteria) would avoid anyhow as times of operation coincide with a surplus of RE generation. Therefore, the additionally-avoided curtailment is expressed as the balance of the actually-avoided curtailment under the local pricing mechanism (literal e) and the "anyhow" quantity.

3.3 Assessment of Economic Distribution Impacts

Implementing new policies does not only impact the system costs, but also the market participants' economic figures. Presumably, the implemented policies may not only lead to winners, but might also make people become losers. The latter group is likely to raise complaints which then cause additional (e.g. judicial) friction to the political process. On the other hand, the economic figures are one motivational factor influencing the homeowners' investment decision and, thus, in the long run, have an impact on the share of environmentally-friendly heating technologies in the market (cf. Michelsen and Madlener (2013), Bauermann et al. (2014)). Therefore, it is important to take a closer look at the distributive effects of different design options. The following section gives a general derivation of equations used for the assessment. Stylized choices representing different policy options are explained thereafter.

For the purpose of evaluating the distribution effects, the scheme in figure 3 and, in particular, the financial flows illustrated therein are reconsidered. The electricity consumption results in cash flows (for convenience, also called payments $CF_{HH/HP}^{out}$). For ease of understanding, the variable costs of end consumers are divided into two components: The local price $p_{loc,t}$ and the end consumer charges $ECC_{HH/HP,loc}$ which include, among others, constant grid charges of the local grid and higher levels, levies (e.g. for renewable support) and taxes. Analogically, the marginal revenue is split into the local price and into a local market premium $MP_{RE,loc}$. Thus, the end consumer charges and the market premiums represent regulatory components whereas the local price represents the market-driven component. By changing the regulatory components, the policy maker can influence the distribution of system benefits as will be shown below.

The system does not only contain the local generators and consumers, it also contains the distribution grid which is controlled by the DSO. In addition to the provision of technical services, for the purpose of this analysis, the DSO is seen as agent who has to source the remaining electricity demand from and pass the remaining generation through to the overarching system. The present work supposes that the overarching (or "global") market conditions are exogenous to the local system[1] and, therefore, the balance of the electricity which is not generated and consumed locally is procured or sold respectively at the wholesale market conditions (i.e. the prevailing wholesale market price $p_{WSM,t}$ and the end consumer charges $ECC_{HP/HH,glob}$ and the market premiums MP_{glob} of the overarching system). The DSO position encompasses the residual claims, i.e. the system cost reduction corrected by the benefits and costs assigned to other stakeholders. The question whether and how the DSO may pass on these costs or benefits to the rate payers or tax payers is excluded from the discussion.

In table 1, the equations for the payments of consumers $CF_{HH/HP}^{out}$ and from a system perspective CF_{SYS}^{out} and the payments to producers / the system $CF_{RE/SYS}^{in}$ are listed. The system perspective considers all financial flows which cross the system boundary in figure 3. For the electricity used locally, grid charges for the HGL c_{HGL} are included in CF_{SYS}^{out}. Furthermore, the grid charges for the LVG remain within the system. SC_{SYS}, in turn, stands for the system costs which incur to the considered system, i.e. the aggregate of HH, HP, RE and DSO. These are evaluated at the global market conditions as explained above. The columns differentiate between a "local pricing regime" (applicable for the considered system) and a "global pricing regime" which would be the classical regulatory pricing scheme without local price signals and which always builds the base case for comparison. In the global pricing regime, RE generators receive a compensation payment at a rate of $p_{comp,t}$ (per curtailed quantity). Such payment is not necessary in the case of a local pricing regime as – in an efficiently-designed local market – the local prices will adjust in a way that RE generators are not willing to feed in any more electricity once the grid reaches its technical limit.

[1] Which holds if the percentage of regions with local prices is small compared to the overarching system.

Table 1: Summary of cash flows, system cost and the DSO position

	Local Pricing Regime	Global Pricing Regime	
CF_{HH}^{out}	$\sum_{t=1}^{8760} P_{HH,tot,t}\left(p_{loc,t} + ECC_{HH,loc}\right) \Delta t$	$\sum_{t=1}^{8760} P_{HH,tot,t}\left(p_{WSM,t} + ECC_{HH,glob}\right) \Delta t$	(8)
CF_{HP}^{out}	$\sum_{t=1}^{8760} P_{HP,tot,t}\left(p_{loc,t} + ECC_{HP,loc}\right) \Delta t$	$\sum_{t=1}^{8760} P_{HP,tot,t}\left(p_{WSM,t} + ECC_{HP,glob}\right) \Delta t$	(9)
CF_{RE}^{in}	$\sum_{t=1}^{8760} P_{RE,tot,t}\left(p_{loc,t} + MP_{loc}\right) \Delta t$	$\sum_{t=1}^{8760} P_{RE,tot,t}\left(p_{WSM,t} + MP_{glob}\right) \Delta t + \sum_{t=1}^{8760} \tilde{P}_{RE,t}\, p_{comp,t}\, \Delta t$	(10)
CF_{SYS}^{in}	$\sum_{t=1}^{8760} \left(P_{RE,tot,t} MP_{glob} + P_{RE,rem,t} p_{WSM,t}\right) \Delta t$	$\sum_{t=1}^{8760} (P_{RE,tot,t} MP_{glob} + P_{RES,rem,t} p_{WSM,t}) \Delta t$	(11)
CF_{SYS}^{out}	$\sum_{t=1}^{8760} \Big(P_{HH,loc,t}\left(ECC_{HH,glob} - c_{HGL} - c_{LVG}\right) + P_{HH,rem,t}\left(p_{WSM,t} + ECC_{HH,glob} - c_{LVG}\right) + P_{HP,loc,t}\left(ECC_{HP,glob} - c_{HGL} - c_{LVG}\right) + P_{HP,rem,t}\left(p_{WSM,t} + ECC_{HP,glob} - c_{LVG}\right)\Big) \Delta t$	$\sum_{t=1}^{8760} \Big(P_{HH,loc,t}\left(ECC_{HH,glob} - c_{HGL} - c_{LVG}\right) + P_{HH,rem,t}\left(p_{WSM,t} + ECC_{HH,glob} - c_{LVG}\right) + P_{HP,loc,t}\left(ECC_{HP,glob} - c_{HGL} - c_{LVG}\right) + P_{HP,rem,t}\left(p_{WSM,t} + ECC_{HP,glob} - c_{LVG}\right)\Big) \Delta t$	(12)
SC_{SYS}	$CF_{SYS}^{out} - CF_{SYS}^{in}$	$CF_{SYS}^{out} - CF_{SYS}^{in}$	(13)
SC_{DSO}	$SC_{SYS} - CF_{HH}^{out} - CF_{HP}^{out} + CF_{RE}^{in}$	$SC_{SYS} - CF_{HH}^{out} - CF_{HP}^{out} + CF_{RE}^{in}$	(14)

Table A.1 in Appendix A provides a further breakdown of above equations. The savings for the consumers can be expressed as the difference of payments in a global and a local pricing regime. Similarly, the change in revenues of RE generators can be assessed. Furthermore, a decrease in system costs (i.e. balance between local and global values) can be interpreted as system benefits. If the change in the DSO position (local minus global values) is negative, it indicates operational cost savings. These can be used either to finance support schemes for RE, flexible consumers, cost coverage for the additional system services of the DSO (related to the implementation and operation of a local market) or remain as socio-economic welfare gains. The different options of distribution of the system cost savings are analysed by means of a scenario analysis presented in section 4.2.

4 Application

4.1 Test Case

A grid sample which contains PV systems and households with and without HPs is used as a test case. The grid topology represents a typical example for a low voltage (LV) level grid in rural regions in Germany. The grid representation is based on real grid data, including grid topology, transformer capacities, line properties and installed grid devices. As it is aimed at evaluating the benefits of local pricing policies as alternative to traditional grid expansion the grid characteristics are not altered from the current status.

In addition, the locations of currently-installed PV systems and their orientations are used. The installed PV capacities are scaled up in order to anticipate future grid load situations. The overall scaling factor is 2.3, which reflects the forecast increase of the German PV capacity until 2050 (cf. Prognos AG, EWI, GWS (2014)). The nodes to which PV systems are connected are assumed to remain unchanged.

Similarly, an increased percentage of households is equipped with space heating by air-water HPs. The percentage is chosen in accordance to the expected market share of HPs in the heating market for households in 2050 (according to Biogasrat e.V. (2012)). Thermal and other building characteristics are chosen in accordance to the sample one-family house given in DIN EN 12831 (2003). The layout of HPs is preformed according to the technical planning guidelines (Novelan (2013)), the technical data (HPs and thermal storages) is then sourced from the manufacturer's documents (Panasonic Deutschland (2014a) and Panasonic Deutschland (2014c)).

In the present model, it is assumed that HPs and PV systems can behave elastic in response to price signals while common household appliances are supposed to be inflexible and being modelled by historic load measurement data of the DSO. Irradiance observations of 2014 at a close-by location to the assessed grid is sourced from DWD (2015a). End consumer charges and market premiums are also based on 2014 data (BMWi (2015), BDEW (2014)).

The real grid contains 5 feeders which, for the purpose of this study, are presumed to be identical. That is to say, it is sufficient to analyse one feeder in detail. Figure 6 illustrates the grid topology of the considered LV grid and its schematic including the numbers of connected market participants.

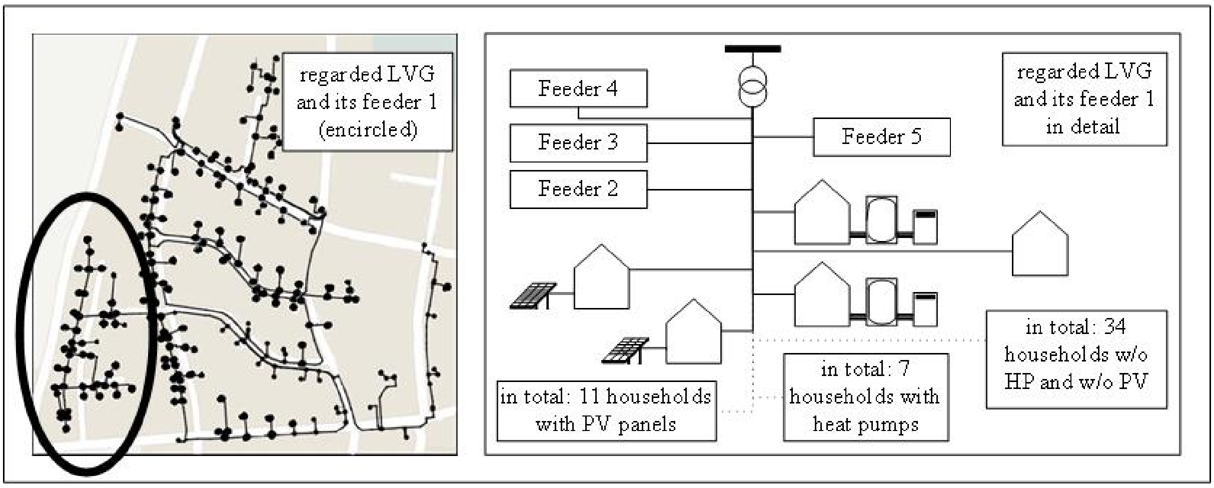


Figure 6: Scheme of grid topology of the considered LV grid (left) and abstracted illustration of the feeders including the market participants in feeder 1 (right)

A short summary of key characteristics is given in table 2. For a more comprehensive list of test case data sources and methods, the reader is referred to table B.1 in Appendix B.

Table 2: Key characteristics of test case (feeder 1)

Description	**Value**
Aggregated installed PV peak capacity	220 kW_p (11 units)
Number of HPs	7
Nominal thermal output and corresponding electrical consumption of each HP	9 kW_{th} / 1.86 kW_{el}
Thermal storage volume for each HP	1,760 l
Voltage level of LVG	400 V
Transformer capacity (available to feeder 1)	80 kVA

4.2 Scenarios

In order to evaluate the impact of various design choices (cf. section 3.3) stylized scenarios are considered representing the extreme choices satisfying the claims of different interest groups. The scenario description is given in table 3.

Table 3: Explanation of tested scenarios and describing equations

Scenario description	**Main equations**
Scenario 0 / No local policy adjustment	
There is no difference between local and global end consumer charges and market premiums. The savings and the change in revenues solely result from the difference between the local and global market price and the compensation for curtailment.	$ECC_{HH,loc} = ECC_{HH,glob}$ $ECC_{HP,loc} = ECC_{HP,glob}$ $MP_{loc} = MP_{glob}$
Scenario A / No non-flexible profiteers	
As HHs do not participate in the local market (not adjusting the demand to the local supply), the end consumer charges of HHs are adjusted in a way that the sums of their payments in a global and a local pricing regime are equal. I.e. there are no savings for HHs.	$ECC_{HH,loc} = ECC_{HH,glob} +$ $\frac{1}{\sum_{t=1}^{8760} P_{HH,tot,t} \Delta t} \sum_{t=1}^{8760} P_{HH,tot,t} (p_{WSM,t} - p_{loc,t}) \Delta t$ $ECC_{HP,loc} = ECC_{HP,glob}$ $MP_{loc} = MP_{glob}$
Scenario B / No disadvantage to RE generators	
Germany and other countries provide RE generators with certain privileges such as off-take prioritization and compensation payments in case of curtailment. If such privileges are to be maintained without exception (e.g. to incentivise additional investments), the sums of payments to the RE generators shall be equal in a global and a local pricing regime.	$ECC_{HH,loc} = ECC_{HH,glob} +$ $\frac{1}{\sum_{t=1}^{8760} P_{HH,tot,t} \Delta t} \sum_{t=1}^{8760} P_{HH,tot,t} (p_{WSM,t} - p_{loc,t}) \Delta t$ $ECC_{HP,loc} = ECC_{HP,glob}$ $MP_{loc} > MP_{glob}$, so that $CF_{RE}^{in} \vert_{local\ pr.regime} = CF_{RE}^{in} \vert_{global\ pr.regime}$

Scenario C / Economic feasibility of flexible HPs	
In order to provide long-term incentives for the installation of flexibility measures for HPs (thermal storage and related equipment, smart grid / forecasting equipment, etc.), potential owners of such equipment must anticipate that the installation is economically feasible. The electricity cost savings of the HP, which result from relatively low local prices and local end consumer charges, may contribute to such economic viability. Thus, in scenario C, the local end consumer charges are adjusted in a manner that the annual electricity cost savings provide for the increase of operational expenses $\Delta OPEX_{flex}$ and the increase of the annualised capital expenses $CAPEX_{flex,annualised}$ due to flexibility measures.	$ECC_{HH,loc} - ECC_{HH,glob} = \frac{1}{\sum_{t=1}^{8760} P_{HH,tot,t} \Delta t} \sum_{t=1}^{8760} P_{HH,tot,t}(p_{WSM,t} - p_{loc,t}) \Delta t$ $ECC_{HP,loc} < ECC_{HP,glob},\ so\ that$ $CF_{HP}^{out}\vert_{local\ pr.regime} + CAPEX_{flex,annualised} + \Delta OPEX_{flex} = CF_{HP}^{out}\vert_{global\ pr.regime}$ $MP_{loc} = MP_{glob}$
Scenario D / Orientation towards local market participants	
This scenario combines the claims of HP owners and RE generators as stated for scenario C and B, respectively.	$ECC_{HH,loc} - ECC_{HH,glob} = \frac{1}{\sum_{t=1}^{8760} P_{HH,tot,t} \Delta t} \sum_{t=1}^{8760} P_{HH,tot,t}(p_{WSM,t} - p_{loc,t}) \Delta t$ $ECC_{HP,loc} < ECC_{HP,glob}\ ,so\ that$ $CF_{HP}^{out}\vert_{local\ pr.regime} + CAPEX_{flex,annualized} + OPEX_{flex,annualized} = CF_{HP}^{out}\vert_{global\ pr.regime}$ $MP_{loc} > MP_{glob}\ ,so\ that$ $CF_{RE}^{in}\vert_{local\ pr.regime} = CF_{RE}^{in}\vert_{global\ pr.regime}$

The resulting allocation of system cost savings, the operational cost savings for HPs and HHs and revenue changes for RE generators are given in section 5.3.

5 Results and Discussion

5.1 Price Signals for Grid-Beneficial HP Operation

Figure 7 shows the HP electricity consumption, the local prices and whether the upper storage restriction is binding during one exemplary week. It can be observed that the operating decision of HPs is clearly driven by the local prices as long as the technical constraints allow. Thus, during times of relatively low local prices (for the case in figure 7 due to congestion) the HP starts to operate and continues until the thermal storage is fully charged or the prices increase again (due to disappearing congestion). If the local prices remain at a very low level for several hours HPs can hardly benefit from the oversupply any longer as the technical limits are reached frequently.

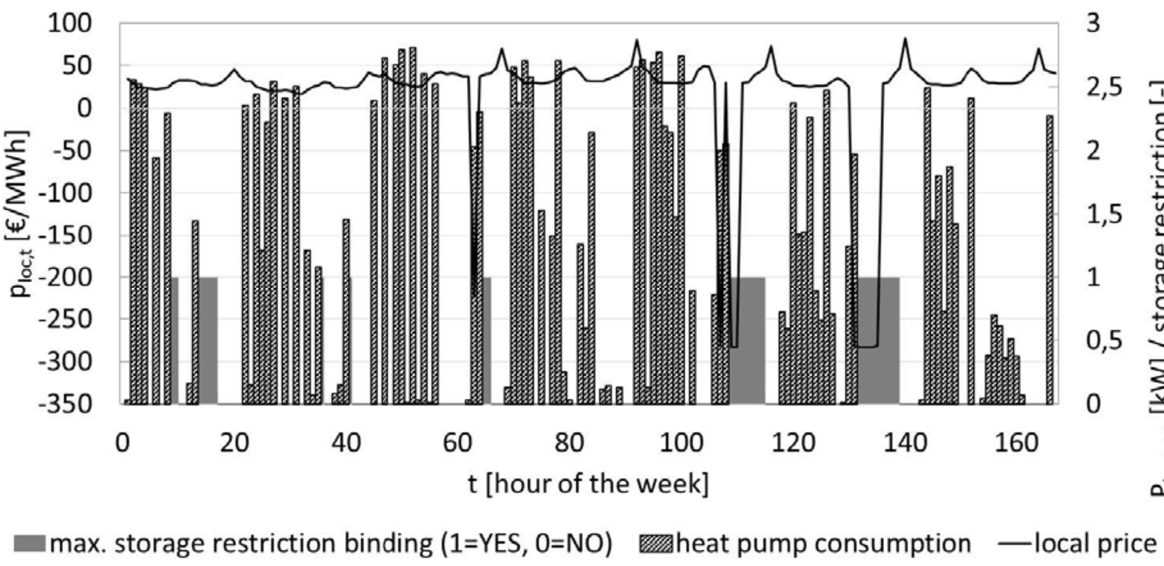


Figure 7: Consumption of one HP (bars), indicator whether upper storage restriction is binding (area, 1= binding, 0 = non-binding) and local prices (line) for one exemplary week of March

Especially in transition months such as March, heat demand as well as local infeed occur concurrently so that the local price signals incentivise HPs to operate (cf. the three periods of negative prices in figure 7 and HP consumption at the beginning of these periods). Notably, the second period of negative local prices is interrupted, i.e. the HP operation contributes to the elimination of congestion. Thus, the analysis shows that local prices allow, in general, to incentivise price-oriented HPs to operate in a more grid-beneficial way. However, the results also make clear that certain restrictions exist which prevent further reduction of curtailment. E.g. this can be observed in the second and third period of negative prices where a charged storage prevents the further use of the HPs. The effects of this and other restrictions are quantified as follows.

5.2 Potential Analysis – Theoretical and Exploited Potential

Figures 8a and 8b show the curtailed amounts and, thus, the quantities which the use of DSM aims to integrate into the energy system. Figures 8b to 8e illustrate the impact of various real-world restrictions on the achievable demand side flexibility. Figure 8f includes the "anyhow" quantity. The literals of the figures correspond to the literals of the methodological explanation in section 3.2. The respective quantities are provided in table 4.

For the given test case, it is observed that – without local prices – the curtailed power reaches up to 120 kW (distance on the vertical axis in figure 8a) and curtailed electricity generation during the complete year is around 26 MWh. Thereof, 49.6 % occur during the non-heating period, which decreases the DSM potential by HPs accordingly.

In figure 8c, the steepness of the duration curve of the curtailed power induces that the electrical power which the HPs could possibly consume (under due consideration of their control explained in section 3.2) is frequently insufficient to avoid the entire curtailment. This limitation diminishes the DSM potential further by 34.6 %.

Additional reductions of 4.0 % and 8.2 % are caused by storage capacity restrictions and forecasting impreciseness, respectively.

Finally, the net avoided curtailment (figure 8f) by applying local prices under the given setup is only 882 kWh (actual minus "anyhow" avoided curtailment).

The discrepancy between curtailed PV generation without DSM by HPs and the achieved reduction of curtailment by that means is significant. In the test case, only 3.6 % of the curtailment can be avoided. Thus, it is appropriate to discuss the sensitivity of the results which is done subsequently following the sequence of the literals of table 4 and section 3.2.

It is obvious that the test case represents a quite extreme example with high curtailment. Therefore, the percentage figures should not be over-interpreted. However, in terms of absolute curtailment reduction, the case is rather optimistic on the contribution of flexibility from HPs for the same reason.

Creating additional use of the HPs during the summer months may be thinkable. Air conditioning may raise the capacity factor of HPs. Yet, due to its currently limited installation numbers in Germany and other central European countries, increasing the use of air conditioning would have adverse effects with respect to the original climate goals. Warm water supply by HPs is another option which is more compatible with the climate goals. However, its share in end consumption of heating appliances is much lower than the one of space heating (in Germany: 17 % vs. 76 %, cf. AGEB (2014)) and technicalities related to supply temperature levels (cf. section 3.2) further decrease its leverage.

Increasing the penetration of HPs could help avoiding further curtailment. However, the marginal utility of each HP will decrease. Section 5.3 will provide the reasoning why the installation of further HPs will not be beneficial from a system cost perspective. The same argument applies for the installation of additional storage capacity.

An evident upside potential is the improvement of the forecasting adequacy (local prices, heat demand and ambient temperature). Great part of these potentials could certainly be leveraged so that the avoidance of around 2,000 kWh of curtailment seems realistic for the given test case.

Further upside potential exists for other combinations of RE types (such as wind power) and/or other DSM devices/facilities (like household appliances, industrial plants, etc.). Their complementarity is likely to bear greater potential as the correlation of daily infeed and daily demand may be higher. However, such analyses would require a whole new scenario setup. I.e. the regarded grid would be different as wind power plants are typically connected to higher voltage levels to which, in turn, other consumer types are connected. Thus, this assessment is left to further research.

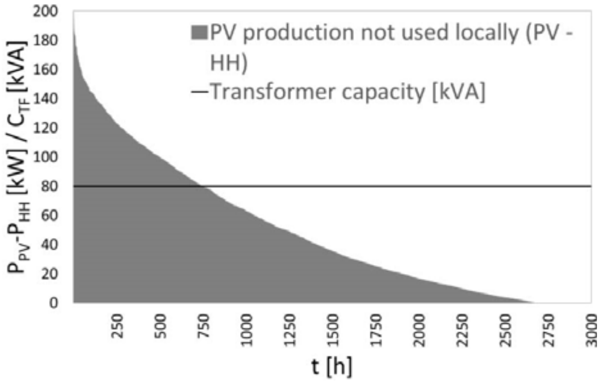


Figure 8a: Duration curve of residual PV infeed and capacity constraint of the transformer

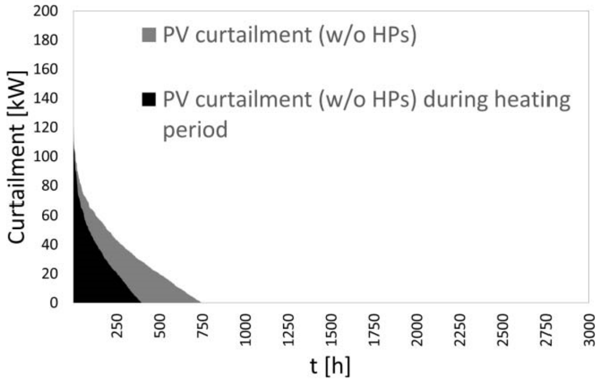


Figure 8b: Duration curve of PV curtailment during all hours of the year and during heating period only

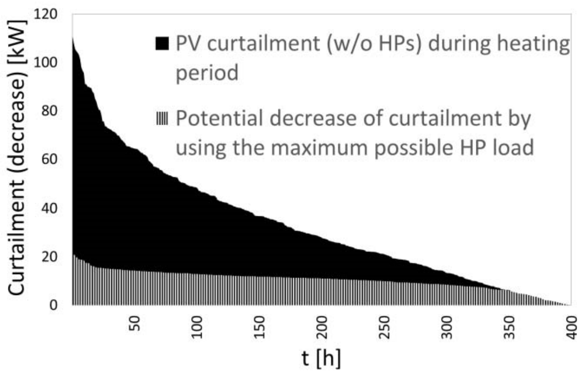


Figure 8c: Duration curve of curtailment without HPs and its potential decrease if using maximum possible HP loads

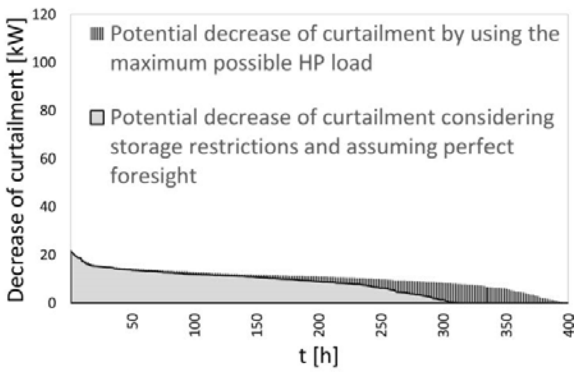


Figure 8d: Duration curve of potential decrease of curtailment using maximum possible HP load considering storage restriction or not

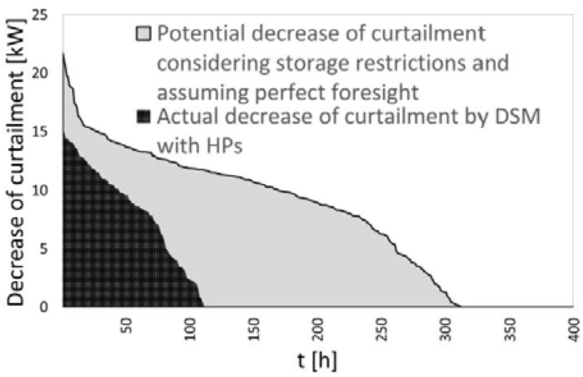


Figure 8e: Duration curve of decrease of curtailment under perfect and imperfect foresight

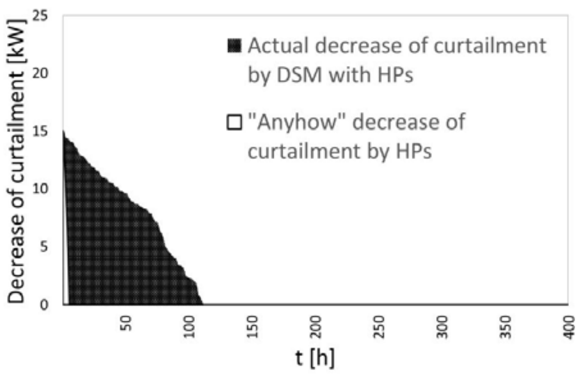


Figure 8f: Duration curve of decrease of curtailment by operating HPs in a price responsive manner and according to technical criteria

Table 4: Summary of quantitative results of the potential assessment

Position	Quantity	Share of curtailment without HPs	Share of maximum possible PV generation
Maximum possible PV generation	199,979 kWh	n.a.	100.0 %
PV production not used locally (PV – HH)	146,537 kWh	n.a.	73.3 %
PV curtailment (w/o HPs) (a)	26,198 kWh	100.0%	13.1 %
PV curtailment (w/o HPs) during heating period (b)	13,195 kWh	50.4%	6.6 %
Potential decrease of curtailment by maximum possible HP load (c)	4,151 kWh	15.8%	2.1 %
Potential decrease of curtailment considering storage restrictions and assuming perfect foresight (d)	3,084 kWh	11.8%	1.5 %
Actual decrease of curtailment by DSM with HP (e)	**933 kWh**	**3.6%**	**0.5 %**
"Anyhow" decrease of curtailment by HPs (f)	51 kWh	0.2%	0.0 %
Actual decrease without "anyhow" quantity	**882 kWh**	**3.4 %**	**0.5 %**

Finally, it should be noted that the potential analysis shown above does not consider the transaction costs in local pricing regimes. These would decrease the potential for operational system cost savings even further.

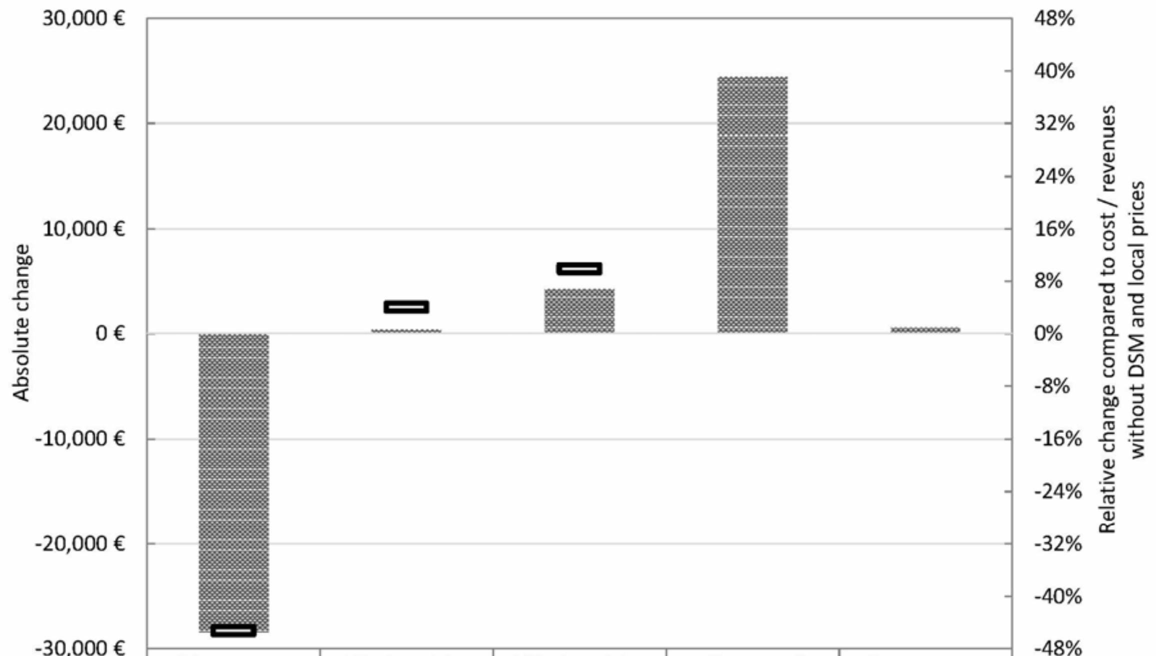
5.3 Allocation Scenarios - Distribution of Benefits

5.3.1 Base Case – Scenario 0

In Figure 9, the absolute and relative economic impacts on the considered market participants are illustrated. The numbers show that implementing local prices without adjusting regulatory pricing components especially affects the revenues of RE generators. These are diminished by approx. 45.3 % of which 12.5 % (7,848 €) are due to missing compensation of curtailment and the remaining decrease of 32.8 % (20,561 €) results from the RE generation at times of congestion (or prevented congestion[2]) at accordingly low (mostly negative) prices. The fact that RE generators continue to feed in electricity to the grid is a consequence of their economic rationale: Even though the local prices are negative the market premiums will still make the contribution margin for RE generator be 0 or slightly positive. At such contribution margins, it is reasonable for RE

[2] Prevented congestion refers to times where the local pricing mechanism eliminates congestion.

generators to feed in electricity to the distribution grid. However, these contribution margins are significantly lower than the lowest contribution margin that RE generators could have achieved under a global pricing regime[3].



	RE revenue change	HP electricity cost savings	HH electricity cost savings	Change of DSO position	System cost savings
Scenario 0 (abs.)	-28,410 €	385 €	4,235 €	24,380 €	590 €
Scenario 0 (rel.)	-45.3%	4.0%	9.9%		

Figure 9: Distribution effects between market participants for scenario 0

The HP owners' electricity cost savings are quite low only representing approx. 4.0 % of the electricity costs under a global pricing regime. Such low improvement is reasonable as the average price decrease (local vs. global) is only 2.47 ct/kWh. Compared to the reference end consumer price this constitutes only 8.5 %. Analysing the reasons for HPs using less than half of the average price decrease is straightforward considering the results of section 5.2.

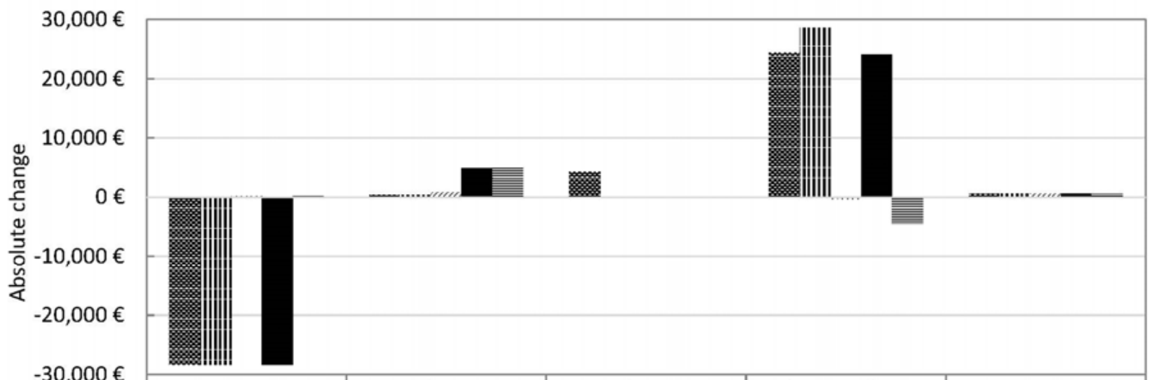
The HHs are able to take an above-average advantage from local prices as the correlation between the HH loads and RE infeed is higher.

The change of the DSO position is quite positive (savings of 24,380 €). However, this is a consequence of the distribution effects (i.e. the revenue decrease of RE generators) rather than of cost savings in the overall system which only contribute 2.4 % to such improvement.

[3] In 2014, the minimum wholesale market price was -6.5 ct/kWh. Considering the average remuneration of PV infeed at 31.6 ct/kWh (BMWi (2015)), the average wholesale market price of 3.2 ct/kWh and, thus, an average market premium of 28.4 ct/kWh leaves a contribution margin of 21.9 ct/kWh during the most-unfavorable hour of 2014 under a global pricing regime.

5.3.2 Scenarios A - D

Figure 10 shows how alternative policy mechanism designs which change the regulatory components of the local prices may alter the economic impacts on the market participants. For scenario A, the main observation is that the net benefits for the DSO increase (while the benefits for the HHs are 0 – which has been the scenario's stipulation). The end consumer charges have no effect on the remaining market participants as the HH behaviour does not change due to its inflexibility.



	RE revenue change	HP electricity cost savings	HH electricity cost savings	Change of DSO position	System cost savings
Scenario 0 (abs.)	-28,410 €	385 €	4,235 €	24,380 €	590 €
Scenario A (abs.)	-28,410 €	385 €	- €	28,615 €	590 €
Scenario B (abs.)	195 €	746 €	- €	-342 €	600 €
Scenario C (abs.)	-28,410 €	4,869 €	- €	24,130 €	590 €
Scenario D (abs.)	195 €	4,869 €	- €	-4,465 €	600 €
Scenario 0 (rel.)	-45.3%	4.0%	9.9%		
Scenario A (rel.)	-45.3%	4.0%	0.0%		
Scenario B (rel.)	0.3%	7.8%	0.0%		
Scenario C (rel.)	-45.3%	50.7%	0.0%		
Scenario D (rel.)	0.3%	50.7%	0.0%		

Figure 10: Distribution effects between market participants for scenarios 0 and A to D

Scenario B provides some more interesting results: The revenue change of RE generators is 0 (as postulated), but the electricity cost savings for HPs increase. It can be observed that the electricity cost savings of HPs increase by about 94 %. This is the consequence of the higher local market premium which the RE generators receive: In order to compensate the revenue losses that the RE generators incur due to lower local prices and abolished compensation for curtailment the market premium has been increased from approx. 28 ct/kWh to more than 70 ct/kWh for scenarios B and D. Considering the economic rationale of RE generators (explained in section 5.3.1) the pricing mechanism induces much lower local prices at times of congestion. Hence, the average price decrease (local vs. global) is 5.77 ct/kWh meaning 19.8 % of the end consumer price. Still the leverage for HPs is bound to the technical limitations explained in section 3.2 and the HP electricity cost savings remain far from what would make the additional flexibility investments economically feasible. This would require a reduction of the $ECC_{HP,loc}$ by 12.3 ct/kWh enabling HP operational cost savings of approx. 4,869 € (scenarios C and D).

For all scenarios, the system cost savings remain almost unchanged from scenario 0. This is the implication of the technical restrictions analysed in sections 3.2 and 5.2. The slight improvement in system costs in scenario B and D results from the more pronounced price signals for the cost-optimising control of the HPs.

Finally, scenario D reveals that the net effect on the DSO position is negative. I.e. if RE generators are not to suffer from disadvantages (compared to the situation in a global pricing regime) and the incentives for features enabling HPs to operate flexibly are to be sufficient the operational costs of the DSO (i.e. of the rate payers and/or tax payers) will increase.

An alternative policy choice might then be to avoid extra costs to the DSO. Then, at least one market participant would need to make up for the gap of 4,465 €. Applying the costs-by-cause principle RE generators would suffer a decrease of approx. 7.1 % of their former revenues. This would enable the integration of more RE into the energy system (avoidance of 882 kWh of curtailment) and imply the advantage of enabling HPs to operate more resource-efficiently (reduction of electrical consumption by 488 kWh due to the increased flexibility). Translating this to reduced CO_2 emissions that is almost 1 ton of CO_2 reduction per year.

6 Conclusion

The results in section 5.1 indicate that local pricing mechanisms can provide short-term incentives for orienting HPs towards grid-beneficial operation. However, the analysis in section 5.2 reveals that the complementarity of HPs and PV is limited and the potentials claimed in several publications may be called into question. The technical measures to achieve a positive effect in terms of operational system cost reduction are very limited for the given scenario. Outside the scenario, e.g. different combinations of generator and consumer types may offer higher potential. Hence, the analyses disprove any generalized claims about the efficiency of local pricing - yet obviously it does not prove that local pricing is of no worth in general.

Section 5.3 demonstrates that it is not feasible – in the given setup – to incentivise investments into flexible HP installations, without accepting additional societal cost or reducing the revenues of RE generators. It is shown that – despite limited merits in terms of system costs – the redistributive effects of local pricing mechanisms are very significant. Given the huge redistributive effects, any proposal for the use of local prices will encounter massive opposition unless accompanied by a proposal for readjustment of charges and levies.

Concluding, any change towards local pricing policies will require careful cost-benefit analyses and policy makers have to pay attention to the redistributive effects as they will impact the long-term incentives for investment.

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Appendix

Appendix A – Further Breakdown of Equations for Assessment

Table A.1: Further breakdown of equations for assessment

Described Figure	Descriptive Terms	
SC_{SYS}	$E_{HH,tot}(ECC_{HH,glob} - c_{LVG}) - E_{HH,loc}c_{HGL} + \sum_{t=1}^{8760} P_{HH,rem,t}p_{WSM,t}\Delta t +$ $E_{HP,tot}(ECC_{HP,glob} - c_{LVG}) - E_{HP,loc}c_{HGL} +$ $\sum_{t=1}^{8760} P_{HP,rem,t}p_{WSM,t}\,\Delta\,t\ - \sum_{t=1}^{8760} P_{RE,loc,t}MP_{glob}\,\Delta t -$ $\sum_{t=1}^{8760} P_{RE,rem,t}(p_{WSM,t} + MP_{glob})\Delta t$	(A.1)
ΔSC_{SYS}	$-\Delta E_{HP,tot}ECC_{HP,glob} + \Delta E_{HP,loc}c_{HGL} - \Delta(\sum_{t=1}^{8760} P_{HP,rem,t}p_{WSM,t}\Delta\,t) +$ $\Delta E_{RE,tot}\,MP_{glob}\ + \Delta(\sum_{t=1}^{8760} P_{RE,rem,t}p_{WSM,t}\,\Delta\,t)$	(A.2)
$\Delta SC_{SYS,RE\ integration}$	$\Delta E_{HP,loc}c_{HGL} + \Delta E_{RE,tot}MP_{glob} = \Delta E_{RE,tot}(c_{HGL} + MP_{glob})$	(A.3)
$\Delta SC_{SYS,tech.\ eff.gains}$	$-\Delta E_{HP,tot}ECC_{HP,glob} - \Delta(\sum_{t=1}^{8760} P_{HP,rem,t}p_{WSM,t}\Delta\,t) +$ $\Delta(\sum_{t=1}^{8760} P_{RE,rem,t}p_{WSM,t}\,\Delta\,t)$	(A.4)
$SC_{DSO}\,\vert_{local\ pr.regime}$	$E_{HH,tot}(\,ECC_{HH,glob} - ECC_{HH,loc} - c_{LVG}\,) - E_{HH,loc}c_{HGL} +$ $E_{HP,tot}(ECC_{HP,glob} - ECC_{HP,loc} - c_{LVG}\,) - E_{HP,loc}c_{HGL} -$ $\sum_{t=1}^{8760} P_{RE,tot,t}(MP_{glob} - MP_{loc})\Delta t - \sum_{t=1}^{8760} P_{RE,rem,t}(p_{WSM,t} - p_{loc,t})\Delta t$	(A.5)
$SC_{DSO}\,\vert_{global\ pr.regime}$	$-E_{HH,tot}\,\bar{c}_{LVG} - E_{HH,loc}c_{HGL} - E_{HP,tot}\,\bar{c}_{LVG} - E_{HP,loc}c_{HGL} +$ $\sum_{t=1}^{8760}\,\tilde{P}_{RE,t}\,p_{comp,t}\Delta t$	(A.6)
ΔSC_{DSO}	$-E_{HH,tot}(ECC_{HH,glob} - ECC_{HH,loc}) -$ $E_{HP,tot}\,(ECC_{HP,glob} - ECC_{HP,loc}) - \Delta E_{HP,loc}c_{HGL} +$ $E_{RE,tot}(MP_{glob} - MP_{RE,loc}) +$ $\sum_{t=1}^{8760}\,P_{RE,rem,t}(p_{WSM,t} - p_{loc,t})\Delta t +$ $\sum_{t=1}^{8760}\,\tilde{P}_{RE,t\,\vert no-flex}p_{comp,glob,t}\Delta\,t$	(A.7)

Here, E is the yearly amount of electricity consumed or generated, respectively. ΔSC_{SYS} stands for the difference in system cost savings achieved by the local pricing mechanism (i.e. system costs without DSM and without local prices compared to those using the local pricing mechanism). $\Delta SC_{SYS,RE\ integration}$ is the part of the system costs savings due to improved RE integration (in the given examples, amounting up to 343 €). The remainder is due to other effects such as the more efficient operation of the HPs, more cost-saving operation of HPs and its feedback effect on the market-based component of the RE revenues. Such remainder is called technical efficiency gains ($\Delta SC_{SYS,technical\ eff.gains}$, in the examples being up to 280 €). In equations A.2 and A.7, it is assumed that the sum of all received grid charges for the LVG must remain unchanged (regardless of the implementation of a local pricing mechanism). For the grid charges for the HGL, this is not the case. In equation A.5, it should be noted that, for the presented case, the price divergence may only exist when $P_{RE,rem,t}$ is positive.

Appendix B – Summary of Test Case and Model Data

Table B.1: Summary of data used for the assessment

System	Data / Method	Source
System configuration		
Installed PV capacity	Scaling factor applied to existing PV capacity	Prognos AG, EWI, GWS (2014)
No. and location of households	Data of actual grid	Proprietary data of the DSO
Household loads	Data sets of actual grid	Proprietary data of the DSO
Number of households with HPs	Forecasted share of household applied to number of households	Biogasrat e.V. (2012)
PV data		
PV panel orientation and location	Data of actual grid	Proprietary data of the DSO
Maximum possible PV infeed	Calculation using PV panel orientation and location and irradiation data	Quaschning (1996)
Building configuration		
Building characteristics	Dimensions (floors, walls, windows), orientation, design heat load, design ambient temperature	DIN EN 12831 (2003), DIN EN ISO 13790 (2008)
Floor heating	Piping dimensions, floor thickness, circulation pump data	Schmidt et al. (2010), DIN EN 1264-2 (2013), Grundfos (2008)
Solar returns of the building	Calculation using window sizes, orientations and respective shading factors and irradiation data	Quaschning (1996), Schild and Willems (2011)
Internal returns of the building	Simplified load profile with habitable-surface-specific heat input for residential buildings	DIN V 4108-6 (2003), Michelsen and Madlener (2013)
Heating system		
HP layout	Thermal nominal capacity according to technical design criteria	Novelan (2013)

HP data	Manufacturer's data (Panasonic WH-SDC09F3E8), approximation of performance map through linear regression	Panasonic Deutschland (2014a), Panasonic Deutschland (2014c)
Thermal storage data	Manufacturer's data (4 x PAW-TE50E3STD) supplemented by temperature limits	Panasonic Deutschland (2014a), E DIN EN 12897 (2014), Schmidt et al. (2010)
Environmental conditions		
Meteorological conditions	Hourly ambient temperature measurements, hourly irradiance observations at location closest to the considered grid	DWD (2015a), DWD (2015b)
Data for annuity calculation of additional flexibility measures of HP		
Investment cost	Prices of additional storage units (PAW-TE50E3STD) according to manufacturer's price list, lump sum for additional accessories, smart grid investment cost estimated based on prices of similar modules	Panasonic Deutschland (2014a), Panasonic Deutschland (2014c), Panasonic Deutschland (2014b)
Operation and maintenance cost	Additional operation and maintenance cost (other than electricity cost) neglected	
Financial parameters	Payoff period of 20 years, interest rate according to the 2014-average yields for government bonds with 20-year maturity, nominal, all issuers whose rating is triple A in the Euro area (representing the lower bound to the effective interest rate relevant to investors).	European Central Bank (2016)
Electricity price level	Myopic expectations (savings dominated by regulatory price component)	
Market and regulatory conditions		
Wholesale market price	Hourly day-ahead electricity prices for the German-Austrian market zone	EPEX Spot SE (2014)

Regulatory conditions	End consumer charges, grid charges and renewables reimbursement based on German average data for 2014	BMWi (2015), BDEW (2014)

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