Energy Economics 71 (2018) 383–402

Contents lists available at ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneeco

Photovoltaics and heat pumps - Limitations of local pricing mechanisms

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ARTICLE INFO

Article history:
Received 14 September 2016
Received in revised form 18 December 2017
Accepted 25 December 2017
Available online 04 January 2018

Keywords:
Integration of renewables
Distribution grid
Local pricing
Agent-based simulation
Demand side management
Heat pump

ABSTRACT

Demand side management has been proposed as one cornerstone for a future sustainable energy system. Local pricing may contribute to enable a smart behaviour of grid users by providing appropriate incentives. In this paper, we apply a local pricing algorithm on distribution grid level. We analyse its effects for a typical German rural low voltage grid with high penetration of photovoltaics and heat pumps. With households using electric heat pumps, a potentially flexible consumer type is implemented in detail. Such setup is used to assess two issues: Firstly, the exploited potential in terms of avoided curtailment and, secondly, redistributive effects of such local pricing mechanism under use of different stylized policy choices. Results show that – even with given local incentives – the consumption adjustment towards an efficient grid usage can frequently not be realized since complementarity of photovoltaics and space heating demand is limited and technical constraints do not allow to overcome this gap. Furthermore, we show that – despite limited merits in terms of system costs – the redistributive effects of local pricing mechanisms are very significant.

1. Introduction

During the last decade, renewable energy (RE) found its way into the electricity generation portfolio. Taking the German case as an example, the gross electricity generation from wind and solar energy sources (non-dispatchable renewables-based technologies) amounted to approx. 93 TWh in 2014, representing 14.9% of the total gross electricity generation (cf. BDEW (2017)). The increasing capacities of RE installations have led to highly fluctuating electricity infeed occurring independently from demand. Such circumstances have entailed the necessity of repeated curtailment of RE generators. Especially, curtailment measures preventing critical situations in the distribution grid have increased substantially in Germany in recent years (BNetz and BKart, 2015). In 2014, compensations of approx. 42.1 million € were paid and a RE generation of 659.1 GWh was curtailed due to critical situations in the German distribution grids. The reduction of RE generation preventing critical situations in 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

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 system operator; Δt: time increment (here: 1 h); *glob* (index): global (simplified for the non-local pricing mechanisms); 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: 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 (also index): low voltage grid; *loc* (index): local; LV: low voltage; *max* (index): maximum (possible); *min* (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; Q(u): voltage dependent reactive power control; 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; T: temperature; T_{design}: design ambient temperature as per DIN 12831; TF (index): transformer; *tol* (index): tolerable; *tot* (index): total; τ_{summer}: non-heating period; U: markup; V: volume; VARMA: vector autoregressive moving average; WSM (index): wholesale market; z (index): heating zone.

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https://doi.org/10.1016/j.eneco.2017.12.032

foreseen (CDU, CSU, SPD, 2013, E-Bridge, IAEW, Offis, 2014 and BMWi, 2015a, 2015b).

The above numbers apply to the German case, but curtailment is not only a German phenomenon: E.g., in Europe, Ireland, Italy and Spain face similar challenges (cf. Lew et al., 2013). In the US, the electricity markets (incl. regulations for RE infeed) are organized somewhat differently and they are more heterogeneous. Nevertheless, system operators have to deal with times of high amounts of local RE infeed and, thus, curtailment for which individual procedures have been implemented (cf. Fink et al., 2009).

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. For the discussion of these incentives and hereinafter, we consider European-style electricity markets. Traditionally, in these types of markets, retail prices for household consumers do not provide these incentives. Firstly, because commonly these retail prices do not reflect real-time wholesale market prices.[1] Secondly, even if this was the case, these wholesale market prices do not reflect local grid constraints/local congestion.[2] 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 (cf. 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, utilization 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. In this regard, it is assumed that financial benefits also need to be apparent to potential market participants in order to accept a local pricing regime. In any case, we take as prerequisite that 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 and Ecofys Germany, 2011, Mueller et al., 2014, Bechem et al. (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 are 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. Photovoltaic (PV) systems and households (HH) with inflexible loads and, to a certain extent, with price-responsive HPs are considered. The penetration of PV systems and HPs has been set according to forecast values (taken from the literature) while the grid's technical features remain unchanged from

[1] Even though there exists the possibility of variable tariffs such as time-of-day tariffs and peak-power-based grid utilization tariffs (see e.g. Steen et al., 2016), energy-based tariffs are the most common tariff type for households. Industrial consumers, for whom a structured procurement of electricity (exploiting the varying wholesale market price) may be within reach, are usually large consumers connected to higher grid levels (which are not taken into account in the present study).

[2] With European-style electricity markets, we especially refer to market designs using zonal pricing. The considered price zones usually comprise a set of transmission grid nodes (to which distribution grids are subordinate) and whose interlinkages by transmission lines are considered in the market clearing process. I.e. within an entire distribution grid, the same price of the overarching price zone applies in these kind of markets, irrespective of distribution grid constraints.