WELFARE EFFECTS OF DYNAMIC RETAIL PRICING IN THE PRESENCE OF FLUCTUATING RENEWABLE ENERGY SUPPLY, CARBON TAXATION AND PLANNING RESERVE MARGIN CONSTRAINTS

Christian Gambardella, Potsdam Institute for Climate Impact Research, P.O. Box 601203, 14412 Potsdam, Germany
Phone: + (49)-331-288-2423, email: chgamba@pik-potsdam.de
Michael Pahle, Potsdam Institute for Climate Impact Research, P.O. Box 601203, 14412 Potsdam, Germany
Phone: + (49)-331-288-2465, email: michael.pahle@pik-potsdam.de
Wolf-Peter Schill, German Institute for Economic Research (DIW Berlin), Mohrenstr. 58, 10117 Berlin, Germany

Overview

European electricity market design faces two major challenges. First, due to everlasting "missing money" concerns reliability in the long-run may be addressed via explicit capacity mechanisms to implement administratively determined resource adequacy levels (planning reserve margins). Secondly, with increasing shares of intermittent energy supply from variable renewable resources (vRES) like wind or solar radiation, short-run security-of-supply crucially depends on increased power system flexibility. In this regard, one of the most (dynamically) cost efficient options to accommodate substantially fluctuating energy supply is demand response (DR) (cf. Mills and Wiser 2014). Simultaneously, demand's lacking responsiveness to price creates significant allocative inefficiencies and stands at the heart of any economic debate on resource adequacy in electricity markets. This major flaw has resulted in distortionary (mostly supply-sided) planning reserve requirements in most liberalized market systems aimed at inducing a predetermined level of firm (supply) capacity on top of anticipated peak demand. To put it in a nutshell, implementing price responsive demand is a decisive element for power market efficiency which is becoming even more crucial in a renewable (non-dispatchable) resources dominated market.

To get a grasp on this quantitatively and qualitatively, we focus on the allocative efficiency gains from increasing DR, here solely understood as price sensitive electricity consumption, when electricity supply and wholesale prices become more volatile with increasing supply shares of vRES. These allocative gains could usually occur since in almost all electricity market systems the vast majority of consumers receive time-invariant retail prices although electricity wholesale prices typically fluctuate very strongly on an hourly basis, and thus they consume either "too much" or "too little" (Borenstein and Holland 2005). Renewable energy supply fluctuations add to the structural fluctuations of electricity demand, thereby increasing time-variability of electricity wholesale prices. Moreover, entry of low-marginal cost vRES capacity reshapes the hourly aggregate supply curve such that long-run equilibrium prices may become much higher during peak-load hours and more often much lower during off-peak hours (cf. Bushnell 2010; Green and Vasilakos 2012). Such changes in the price distribution would imply even larger benefits from increasing price responsiveness of demand combined with dynamic retail pricing. Preliminary results from market simulations indicate that consumer surplus and, thus, welfare gains from both dynamic electricity and capacity pricing may indeed increase with the share of vRES in the market. But this does not necessarily have to be the case at relatively low shares of vRES supply in gross electricity consumption (GEC), because prices may remain on a relatively high level during many hours where vRES capacity is non-available.

Method

We use a partial long-run equilibrium model of a perfectly competitive electricity market complemented with a forward market for firm capacity (cf. Cramton & Ockenfels, 2012). More specifically, an exogenous reliability target is imposed via a fixed planning reserve margin for dispatchable generation capacity only as in Alcott (2012). Analytically, our framework builds largely upon a two-stage investment and operation model alike the approach used by Borenstein and Holland (2005). Thus, all investments in generation capacity are taken at the initial stage while operation and consumption occur at the second stage. As a special model feature, total hourly electricity demand is determined by two types of consumers: a small share which is able to receive and react to prices in real-time (isoelastic demand function) and a majority of consumers who cannot, therefore facing a flat electricity price (Borenstein and Holland 2005). The flat and real-time electricity prices (RTP) are determined in the retail sector, where homogenous retailers engage in Bertrand competition when buying electricity from generators and selling it on to otherwise homogeneous final RTP or flat-rate customers. Retailers also procure firm capacity from dispatchable generation technologies to comply with the exogenous capacity reserve margin (reliability standard). Retailers then decide upon the pass-through of annual costs for capacity to their customers. As electricity consumption costs, these can either be passed on time varyingly, depending on the bindingness of the reserve constraint, or as a constant payment on top of retail electricity prices (Alcott 2012). In contrast to prior approaches we induce two further model extensions: First, we assume large-scale deployment of vRES induced via carbon emissions taxation. Secondly, we assume a discriminatory capacity market where dispatchable generation capacity is traded only, leading to "excess entry" of high marginal cost technologies.

The numerical model is calibrated to fit German market and generation cost data from 2013 and is formulated as a non-linear mixed complementary optimization problem (MCP) using the software package GAMS. We conduct comparative statics with regard to the welfare gains from increasing shares of vRES and of RTP consumers as well as regarding the introduction of dynamic capacity pricing (DICAP) as opposed to constant capacity pricing (CICAP).

Preliminary Results

Our numerical analysis yields three preliminary results with regard to the welfare gains of dynamic, i.e. real-time retail pricing. *First*, total annual welfare gains from increasing the proportion of customers on real-time pricing can be substantially larger at moderate RTP increases in a market with high shares of variable renewable energy supply. For example, increasing RTP from 1% to 20% entails €157 million in annual surplus gains in a market without vRES compared to €344 million with a 71% share of vRES in GEC. *Secondly*, welfare gains from RTP in a market with high shares of vRES supply can also be *lower* than in a market without variable renewables. Under both capacity pricing scenarios we find that welfare gains from RTP in a market with a vRES share of 57% (carbon price of 150€/tCO2) always stay below welfare gains attained in a market without vRES supply. *Thirdly*, and not surprisingly, passing on capacity costs time varyingly can imply higher consumer surplus gains if high shares of vRES are in the market. Yet, this outcome crucially depends on whether the reserve margin constraint is put on absolute peak-demand or on residual peak-demand (annual peak-demand net of vRES supply). In fact, in the latter case introducing dynamic capacity pricing can even result in counterintuitive, overall welfare losses.

The first result reflect the aforementioned shaping effect on the hourly aggregate energy supply curve from entry of low-marginal cost vRES and increased entry of high-marginal cost conventional capacity due to carbon taxation. We would call this the “convexity effect” and it implies that equilibrium prices center on lower levels comparatively more often during off-peak periods, but may reach higher levels during peak or near-peak periods. Benefits from adjusting consumption properly due to RTP are then comparatively larger than in a market without vRES and a less convex aggregate supply curve. Yet, as result number two suggests, there is also a “flattening effect” in a vRES market that can outweigh the “convexity effect”. This is because vRES capacity is often unavailable such that technologies with very similar (high) marginal costs generate electricity in comparatively more hours. If, for a given demand distribution, the amount of hours with a relatively flat aggregate supply curve in the relevant area increases in comparison to a market without vRES (and carbon taxation), then opportunities to benefit from adjusting consumption optimally are reduced. The respective quantitative threshold regarding carbon price level and share of vRES supply depends, of course, on the cost parameter choices and on the average availability of resources such as wind or solar radiation. At this stage, we lack a proper intuition on the welfare losses from dynamic capacity pricing occurring in certain scenarios. A first guess could be redistributional impacts among flat and RTP consumers regarding firm capacity costs.

Conclusions

Our first findings have direct implications for electricity and capacity market design with high shares of fluctuating renewable resources. As also previous studies have already shown, inducing real-time retail pricing can entail high welfare gains even at a very low sensitivity to price. We show that the allocative gains from dynamic retail pricing can be pronounced in a power market with high shares of fluctuating, low marginal cost energy supply from wind turbines or solar PV. Further, we show that in a market with a complementary planning reserve margin induced via a forward capacity market, welfare gains from passing on capacity costs based on time varying scarcity are relatively larger if renewable shares are high. These economic benefits may justify both increased private or public investment in smart meter infrastructure and the introduction of more dynamic retail tariffing schemes. Yet, as results also show, this may only be the case at sufficiently large shares of vRES supply in GEC.

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