Energy Policy 150 (2021) 112065

Contents lists available at ScienceDirect

Energy Policy

journal homepage: http://www.elsevier.com/locate/enpol

Network tariffs and the integration of prosumers: The case of Wallonia☆

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ARTICLE INFO

JEL classification:
Q42
L51

Keywords:
Prosumers
Distribution tariff
Regulation
Tariff simulator
Death spiral

ABSTRACT

In Wallonia, Belgium's southern region, the distribution component of the overall electricity retail tariff is essentially volumetric, i.e. based on the users' energy consumption (in €/kWh). Residential prosumers, moreover, are connected to the grid via a net-metering system. In this paper, we rely on a sophisticated multi-agent tariff simulator – developed in Manuel de Villena et al. (2019, 2020) – calibrated to this specific regional context to model the integration of prosumers into the distribution grid. This simulator enables us to highlight how the emergence of prosumers impacts the distribution network tariff, and to evaluate several tariff reforms currently under discussion: the introduction of a prosumer fee, the introduction of a capacity component and a switch to net-purchasing. Without a change in the metering system, short run reforms can only change the structure of the tariff paid, either to all consumers or to prosumers only. In the long run, especially thanks to smart meters, we consider both the introduction of a net-purchasing system and of a tariff with a capacity component. Our analysis highlights one key added value of smart meters: they allow network tariffs that are fairer and sustainable.

1. Introduction

Distributed electricity generation based on renewable energy sources has boomed globally in recent years. The deployment of this type of decentralized generation helps decarbonize the energy system. However, since distributed generation units are connected to the distribution network –traditionally designed to unidirectionally distribute electricity from the transmission network to residential areas– they induce challenges to the operation of the electricity system. In particular, they change the nature of energy exchanges within the distribution network, which are now bidirectional as households deploying solar photovoltaic panels on their rooftop not only import but can also export electricity. In light of this paradigm change, regulatory interventions related to how these flows are measured and priced are key in the emergence of a more sustainable energy system. For that reason, reforms of the distribution tariffs are on the agenda in many jurisdictions.

The situation of Wallonia, Belgium's southern region, is particularly interesting in many respects. Households have made substantial investments in decentralized energy production sources over the last few years. By the end of 2019, despite a relatively low solar irradiance, over 10% of the households had installed solar photovoltaic (PV) panels and became *prosumers*. This large adoption of PV installations can be explained by two main factors: (i) subsidies and (ii) network regulations. First, generous up-front investment subsidies (either in the form of direct financial support or in tax cuts) as well as production subsidies, mainly via a green certificate system (Boccard and Gautier, 2015), were granted by various jurisdiction levels. Second, favorable network regulations for prosumers helped substantially decrease the electricity bills of PV owners at the household level. According to these network regulations, distribution tariffs in Belgium were (and still are) predominantly based on units of energy consumed, that is, volumetric fees typically in €/kWh. In addition, prosumers are integrated into the grid via a net-metering system, where the exports of electricity are registered by subtracting from the meter the units of energy injected into the grid (which in practice means that the solar production is valued at retail price). In such a context, investing in PV panels substantially decreased the prosumers'

☆ The authors thank the Walloon Region for its financial support (grant TECR).
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https://doi.org/10.1016/j.enpol.2020.112065
Received 16 March 2020; Received in revised form 22 October 2020; Accepted 29 November 2020

electricity bills, as their meters readings, and thereby their electricity bills, could be greatly reduced.

This high take-up rate of PV adoption led to a tense debate in the public and political arena. From 2016 to 2019, 40 out of the 93 Energy Commissions of the Walloon Parliament discussed issues related to prosumers. Since 2018, all forms of subsidies have been phased out for new PV installations. However, the current network regulations have barely changed. One key issue facing the regulator is that Wallonia is lagging behind other European regions in terms of smart meter adoption (ACER/CEER, 2019): as yet, albeit there is a regional target coverage of 80% of households by 2030, few smart meters have been installed (Service Public de Wallonie, 2018). This is 10 years behind the goal set by the 2009 Electricity Directive set at the European Union level. Hence, the mechanical single meters, i.e. the technology in place, limit the way distribution costs can be billed to the grid-connected users, and only the structure of the tariffs can be changed, e.g. by relying more on fixed fees rather than on volumetric ones. Fixed fees can be applied to all users or to prosumers only. The switch to new bi-directional meters for prosumers (mechanical or smart) will make it possible to consider a different price for electricity imported from and exported to the grid, via a net-purchasing system. The roll-out of smart meters will in addition facilitate the introduction of capacity fees (based on units of power withdrawn from the grid, typically in €/kW). Facing a similar policy context in Flanders, Belgium's northern region, The VREG, the energy regulator, decided to switch towards capacity-based tariffs starting from 2022 on (VREG, 2020).

This paper analyzes how different distribution tariff regulations impact the consumption, production, and (possibly) storage behaviors of residential households. For this purpose, we rely on a tariff simulator developed by Manuel de Villena et al. (2021) and we use regional-specific load and solar irradiance profile curves to apply the model to the case of Wallonia. Compared with other simulators used in Kubli (2018) or Schittekatte et al. (2018) to study a related research question, we use an agent-based modeling approach incorporating the region-specific consumption and production profiles of several thousands of heterogeneous households. This simulator enables us to evaluate the impact of various changes in regulation with respect to PV and battery investments, the evolution of distribution network tariffs, the levelized value of electricity (LVOE) of prosumers and non-prosumers, as well as the formers' rate of self-consumption, and the peak power withdrawals and injections. Our work highlights the importance of considering both the distribution tariff design and the technology connecting all electricity users to the network, as only a subset of tariff regulations can be implemented in the absence of smart meters. And, even if our simulations are computed to represent the specific situation of one region, our policy conclusions carry further away to other legislations that want to adapt their distribution tariff to integrate distributed generation.

This paper is organized as follows. In Section 2, we review the literature on the integration of distributed generation into the grid. In Section 3, we describe the current distribution network regulations in place in Wallonia. The tariff simulator is presented in Section 4. Section 5 analyzes the regulatory scenarios implementable with the metering technology in place. Section 6 describes the regulatory reforms and their impact that can be set in the long run with a change of meters. Section 7 concludes our work.

2. Literature review

Our work relates to the literature focusing on the relationship between the emergence of decentralized generation units and the financing of the distribution system, in the context of an unbundled energy system. In the face of decreasing volumes of the electricity sales owing to the presence of prosumers, the distribution system operator (DSO) requires a higher distribution tariff level in order to break-even (Eid et al., 2014). However, as expounded by Brown and Sappington (2017) and Gautier et al. (2018), such a reform, in a context of largely volumetrically based tariffs, makes PV investments even more profitable, further leading to inefficiently large investments in solar PV. This unsustainable financing of the grid is often referred to as the utility death spiral (Simshauser, 2016).

Our numerical model follows up on the works focusing on this feedback loop to analyze different distribution network regulations. While our conclusions are similar to the works previously done on this topic, we contribute to this literature by better fitting our model with respect to the policy context studied, the Walloon Region, on three different levels.

First, compared to Schittekatte et al. (2018) and Schittekatte and Meeus (2020), we use an agent-based modeling approach that considers a large amount of residential households. The energy consumption and production profiles of 6000 heterogeneous households are considered. Thanks to this approach, we are able to make more realistic predictions regarding the decision to invest in PV panels and batteries, including regarding the size of these investments. Similar to the work of Kubli (2018), our simulator allows us to discuss how tariff regulations impact self-consumption and peak power withdrawals. In addition, we also analyze how peak power injections, a key cost driver for a DSO, are influenced by network regulations.

Second, the policy setting is greatly influenced by the metering technology in place. The issue of death spiral is particularly important when a net-metering system is in place, as the energy exported to the grid is sold at the attractive retail price. This is the current metering technology in Wallonia.[1] Hence, the simulator used in this paper is closely related to the ones developed by Darghouth et al. (2016), Castaneda et al. (2017), Young et al. (2019) to analyze network regulations in respectively California, Colombia and New South Wales Australia.[2] Compared to these works, we differentiate the implementable regulations in the short and long run, depending on the available metering technology. In the short run, only the tariff structure can be changed, for all or only a subset of energy users. In the long run, a net-purchasing system can replace the net-metering system to set different prices for the electricity imported from or exported to the grid. In addition, smart meters, will allow complex tariff structures such as capacity-based one. Hence, we believe that it is important to differentiate short run, second best, regulations from long run ones that can take advantage of the technological features of more evolved meters than those currently in place that record flows only with a single meter.

Third, we calibrate our simulator to the context of Wallonia, though not just with respect to the solar irradiance and the typical production profile, as traditionally done in the literature. In this regard, our simulator is parameterized in such a way that the impact of a distribution tariff increase on the decision to invest in a PV installation be similar to the one measured by Gautier and Jacqmin (2020) using PV installation data in Wallonia.

We trust that these three key aspects allow robust policy conclusions.

3. Distribution network tariff and the integration of residential solar PV in Wallonia

Distribution tariffs in Wallonia have been regulated by the regional regulator (CWaPE) since 2014. The regulator uses a cost-plus methodology to fix the distribution tariff. There are 7 DSOs and 13 tariff zones,

[1] Note that a net-metering system is also in place in a majority of U.S. states, in European countries like Denmark, Netherlands, Greece, Hungary or Latvia as well as in various lesser developed countries like India or Brazil (see IEA-PVPS (2019)).

[2] In comparison, Martin and Rice (2018), Solano et al. (2018), Kufeoglu and Pollitt (2019) and Gunther et al. (2019) present a simulator suited respectively for Queensland Australia, Portugal, UK and Germany where a net-purchasing system, coupled with a feed-in tariff, is currently in place.

where the distribution tariff levels vary substantially between zones. The tariff structure, however, is similar in all zones, with a distribution tariff that is essentially volumetric (in €/kWh), and which includes very small fixed fees (around 20 € per household per year, covering the rental of the meter). The other components of the electricity bills (transmission, energy, taxes and other levies) are also based on the consumption level in kWh. Some retailers also include a relatively small fixed fee in their contracts. In 2018, the volumetric part of the distribution tariff ranged from 7.3 c€/kWh to 14.9 c€/kWh, with an average tariff equal to 11 c€/kWh. In Wallonia, the distribution tariff represents 36% of the consumer's final electricity bill, including VAT (CWaPE, 2020); this relatively large share can be explained, at least partially, by the large public service obligations imposed to the DSOs, which include public lighting, social energy tariffs, and the promotion of renewable energy integration.

In Wallonia, almost all meters are mechanical and PV adopters connect their PV installation to the existing meter. Prosumers then have a single meter that runs forward when electricity is imported from the grid, and backward when it is supplied to the grid. To switch to net-purchasing with a different price for power injections and withdrawals, prosumers need to change their metering technology. They can either install a second mechanical meter to register power injection or a smart meter. Smart meters can measure power in addition to energy, thus enabling the introduction of more sophisticated tariff designs such as adding a capacity-based component to the tariff.[3]

Over the current regulatory period (2018–2022), the regulator introduced a prosumer fee in October 2020 (CWaPE, 2019). This fee is to be paid by the prosumers in contribution to the network costs. Such a fee is based on the PV capacity of each prosumer, and is computed to compensate the avoided distribution network fees assuming a self-consumption rate of 37.76%. Its level depends on the tariff zones, but is on average equal to 85 €/kWp. Prosumers have the option to opt-out and install a dual meter (net-purchasing) and pay the regular distribution tariff for their electricity imports.[4] However, while it is useful to measure the concomitance of decentralized production and consumption, the roll-out of smart meters has been slow compared to the targets set at the EU level and the adoption rates of other Member States. The goal is to have 80% of users of the energy network equipped by 2030.[5]

[3] Smart meters still have other advantages that we do not consider here, e.g. the possibility of having time-of-use tariffs. As consumption is recorded almost instantaneously, the tariff can be adapted to follow the trends of the wholesale market price. Our scenarios do not consider such a pricing but only time-independent distribution network fees and electricity prices. For the time being, meters measure net consumption on a yearly basis. Negative meters could also be reset to zero on a weekly or monthly basis. Our main reason for not discussing these changes is that, to our knowledge, there is no discussion to date of implementing such tariffs in Wallonia. This standpoint might change in a foreseeable future as the Electricity Directive (Directive (EU) 2019/944) requires Member States to implement dynamic electricity price contract whenever smart meters are installed.

[4] There is currently a disagreement between the regulator and the regional government on this prosumer fee. For political reasons, the latter wants to compensate the prosumers for the introduction of the fee. As of today, it is not clear how the government plans to do so, except that it wants corrective measures to encourage self-consumption.

[5] There are two other regions in Belgium. The situation in Flanders is very similar to the one in Wallonia where a prosumer fee has already been implemented since 2015 (De Groote and Verboven, 2019). One key difference is that the roll-out of smart meters will soon be completed and that capacity tariffs, similar to the ones discussed here, will be implemented from 2022 on (VREG, 2020). However, note that, in the energy decree modified in 2019, the Flemish government has committed to maintain the net-metering system as a way to value energy flows, for at least 15 years starting from the date of the PV installation. In Brussels, a densely populated region with mostly shared rooftops, PV investments have been scarcer and a net-purchasing system is in place where the import price of electricity is slightly higher than the export price.

4. Tariff simulator

We rely on a multi-agent model to simulate the impact of distribution tariffs on residential consumers' investments in PV modules and batteries. The model is introduced in Manuel de Villena et al. (2019) and described in further details in Manuel de Villena et al. (2021). Appendix 7.2 contains the mathematical formalization of the simulator. We present the main ingredients of this model in Section 4.1, and the main assumptions on which it relies in Section 4.2. We describe the simulated scenarios in Section 4.3.

4.1. Model description

This simulation-based approach relies on a discrete time dynamical system with two types of agents, the users and the Distribution System Operator (DSO), which interact with each other for a given regulatory environment. Users are classified into three categories of agents: consumers, potential prosumers, and prosumers. The interaction between the different categories is represented in Fig. 1.

The model is composed of several modules: an individual optimization module (OPT) that for each potential prosumer computes the levelized value of electricity (LVOE), given their consumption and production profiles and the regulatory environment in place. The LVOE differs from the traditional levelized cost of electricity (LCOE) in that the LCOE only accounts for costs (i.e. it is computed as discounted costs divided by discounted aggregated demand), whereas the LVOE accounts for costs and revenues (i.e. it is computed as discounted costs minus discounted revenue divided by discounted aggregated demand). The second module models the investment decision process (IDP), where the comparison between the LVOE of each individual potential prosumer and the retail electricity price determines the probability that they invest and become actual prosumers. The last module represents the remuneration mechanism (RM) of the DSO – it computes the adjustment of the distribution network tariff performed by the DSO as a consequence of PV (and/or battery) investment. In this regard, the tariff is adjusted so as to cover the costs of the DSO.

Consumers and Prosumers: At the start of the simulation, there are no prosumers and all users draw electricity from the distribution network. However, as the simulation proceeds over the discrete time dynamical system, a subset of users, i.e. potential prosumers, take action to gradually deploy optimally sized PV installations and batteries, thus becoming prosumers. A potential prosumer turns into an actual prosumer depending on the difference between the LVOE and the actual electricity costs without PV installation and on an exogenous probability. We use the results of Gautier and Jacqmin (2020) to calibrate this probability. On the basis of data from residential prosumers in Wallonia, these authors estimate, by means of an econometric analysis, the elasticity of investment in solar PV due to an increase in the volume-based tariff and, therefore, of the electricity price. They estimate that a 1 c€ increase in the price of electricity increases the probability of investment in a PV installation by 8%. We then created a scenario mimicking the conditions observed by Gautier and Jacqmin (2020), called baseline. In this scenario, an increase of 1 c€ in the price of electricity for the initial period leads to an increase in PV investment by 8%. Then from the second period on, this probability evenly decreases as the deployment of PV installations converges to 100% of the potential prosumers (see benchmark in Section 5). Once a user has invested, thus becoming a prosumer, this agent is removed from the subset of potential prosumers and added to the subset of prosumers, which prevents further investment from this particular user.

DSO: The DSO is a regulated entity. The distribution tariff is set by the regulator and computed to a sufficient level so as to cover the costs deriving from the provision of the electricity distribution service. In our model, there is no explicit cost modeling for the DSO. We consider the distribution costs to be constant over time and equal to their historical value. Hence, we model the financing of the DSO as a zero-sum game:

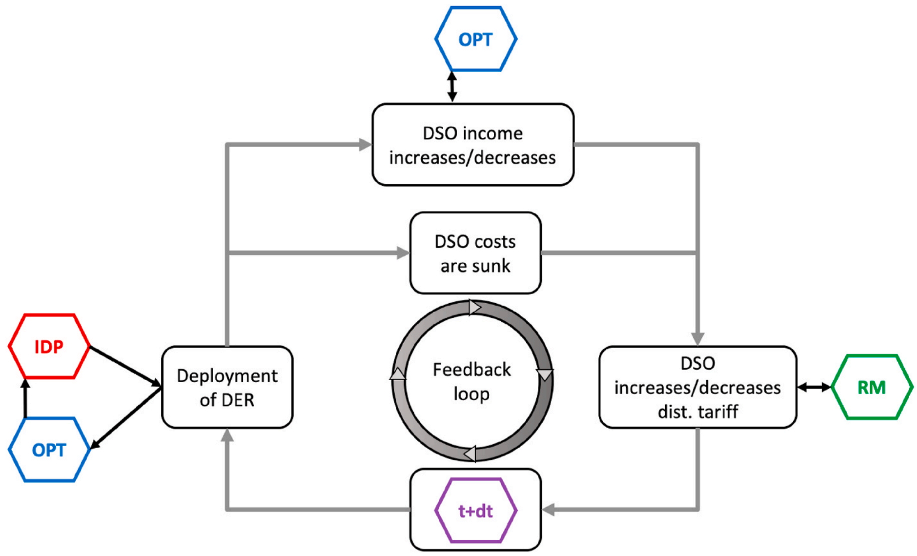

Fig. 1. Multi-agent interaction model with the feedback loop created by the deployment of residential PV panels and by the DSO's remuneration mechanism.

the fixed cost of the DSO must be covered and the different grid tariffs will allocate relatively more or less of this cost to a category of consumers or another. Prosumers' investments in PV installations then change the revenues of the DSO, since these are less reliant on the imports of electricity from the distribution network, but they do not change the grid costs.[6] At every time step of the discrete time dynamical system, the DSO then is allowed to adjust the distribution tariff in order to cover its cost (i.e the DSO must break even and the regulator allows it to increase the tariff to this purpose). The DSO, however, is constrained by the tariff structure, which cannot be changed. Tariff changes then impact electricity costs by typically increasing them, and hence the incentives to invest. Thus, there emerges a feedback loop between the prosumers and the DSO, which is illustrated in Fig. 1.

4.2. Main assumptions

Table 1 reports the main parameters used for running our simulations. The parameters are calibrated to represent the tariff and electricity prices in Wallonia as well as reasonable estimates of PV and battery prices and their evolution. In addition, we use solar irradiance data from Wallonia and standard consumption profile curves for representative consumers for the region. These load profiles have been generated by detailing a household's list of electric appliances and other characteristics. In total, we generated 1000 load profiles, corresponding to different configurations of electric appliances and inhabitants per household using the CREST Demand Model (McKenna and Thomson, 2016). These profiles represent 1000 potential prosumers. In addition, 5000 consumers are introduced by using an average yearly load of consumers in Wallonia. Thus, the total population size is 6000 (5000 consumers and 1000 potential prosumers). While potential prosumers may become prosumers over the time of the simulation, the 5000 usual consumers are regarded as the residual load of the distribution network, representing those users who cannot become actual prosumers due to technical or economic constraints. The set of potential prosumers and its size depend on the characteristics of both the habitations (apartment vs. houses, rooftop size and orientation) and the households (renters vs. owners, income, etc.).

Table 1
Key parameters of the model.

Commodity price (€/kWh)	0.132
Initial distribution tariff (€/kWh)	0.088
Selling price (NP) (€/kWh)	0.040
Population size	6000
Potential prosumers	1000
Initial PV Price (€/kWp)	1500
Initial battery price (€/kWh)	300
Yearly change PV price (%)	−5
Yearly change battery price (%)	−5
PV lifetime (years)	20
Battery lifetime (years)	8
Charging rate (in C.)	4
Discharging rate (in C.)	2.5
Interest rate (%)	2

In Wallonia, around 40% of the houses are detached and 66% of the households are owners. There is, however, a lack of reliable data for PV adoption in Wallonia because all subsidies for solar PV installations have been phased out only recently (July 2018) and previous adoptions were massively subsidized. Hence it is difficult to benchmark it with historical data. The comparison with Flanders, a region that bears many institutional similarities with Wallonia, makes us confident that our model provides a good approximation. There, subsidies were suppressed earlier and we observed that, on average, 0.8% of the households installed PV each year, during the period 2016–2018. This adoption rate was slightly increasing over the period and was 1.07% in 2018. If this rate is kept constant over 10 years, we would have that 10.7% of the households representing 64.2% of the potential prosumers turn to prosumers at the end of the estimation period. As Flanders applies a prosumer fee, the closest scenario to represent the situation in Flanders is the net-metering system with a prosumer fee (NM_{fee} in the subsequent analysis). In our estimations, we find that around 90% of the potential prosumers turned to prosumers in this scenario. This makes us believe that the potential prosumer set is not undersized and the diffusion of PV investments approximates well historical data.

The simulation-based approach is run for 10 periods, each of which corresponds to one year. At the end of each period, the simulation-based approach retrieves the amount of potential prosumers and of prosumers, the capacity of deployed PV panels and batteries, and the distribution tariff level, among other parameters (see Table 1 for a detailed list of the parameters). Then, the simulator starts the simulation of a new period

[6] In practice, the deployment of solar PV modifies the power injections and withdrawals on the grid and thereby impact the grid cost. We discuss further this issue in Section 6.3.

using as starting conditions, our exogenous parameters set initially and the endogenous parameters retrieved from the previous period. Table 1 indicates the initial conditions used for the first step of the simulation.

4.3. Simulated scenarios

We use the simulator to generate six different scenarios, four with the net-metering (NM) system and two with the net-purchasing (NP) system. We consider different tariff structures, mixing fixed (Fix), volumetric (Vol), and capacity (Cap) elements for the distribution tariff. The selected scenarios discuss the most likely reforms of the tariff structure that are being considered in Wallonia. These scenarios are summarized in Table 2. The first three scenarios can be implemented with the current single meters whereas the other three require a change in the metering technology. Scenario 5 can be implemented by installing an additional mechanical meter to the one currently in place or a smart meter. In addition, smart meters also allow the implementation of scenario 4 and 6 with the inclusion of a capacity component in the tariff.

For each scenario, we report the following elements: (i) the percentage of potential prosumers who invested in solar PV and/or batteries, thus becoming prosumers; (ii) the installed capacity of solar PV (in kWp); (iii) the installed capacity of batteries (in kWh); (iv) the mean LVOE of the prosumers; (v) the percentage increase in the electricity costs for the traditional consumers, calculated as the mean percentage increase among the traditional consumers; (vi) the percentage of self-consumption i.e. the share of electricity produced by the PV installations that is consumed on site by prosumers; the peak demand withdrawn from the network; and (vii) the peak production injected into the network.

5. Benchmark and short-term reforms

We set out considering three basic scenarios that can be easily implemented in the short-term, without a change in the metering technology. The current net-metering technology in place exclusively and mechanically registers the yearly energy net consumption. In this context, few reforms are possible. The simplest ones consist in re-balancing the structure of the distribution tariff bill to decrease the volumetric part, and as compensation, adding a fixed fee, either applied exclusively to prosumers or applied to all consumers.

We consider the scenario baseline as a benchmark. This scenario simulates the current situation in Wallonia. We then consider two scenarios where, in addition, non-volumetric fees are introduced.[7] In the first, prosumers pay a fee linked to the installed power of their PV installation (scenario NM_{fee}). This reform is applied since October 2020 on with an average prosumer fee of 85 € per kWp of PV installed. In the second scenario, there is a fixed fee imposed to all users, prosumers and consumers (scenario NM_{fix}) alike. In this case, we consider that the fixed fee must cover 30% of the distribution network costs, the remainder being covered by a volumetric tariff. This threshold has been defined to match the average tariff structure currently applied in Europe (European Commission, 2015).

As shown in Fig. 2, the baseline scenario is the more favorable one for PV investments given that the electricity generated by the PV panels is valued at the retail tariff, which includes the price of the commodity as well as the distribution/transmission fees and taxes. Unsurprisingly then, by the 5th of the 10 periods considered, nearly all potential prosumers had already deployed a PV installation. Fig. 3 shows that this scenario is the fastest one to reach the full potential deployment of PV capacity.

The large and rapid deployment of solar PV panels reduces the total consumption registered by the DSO (as the meter runs backward for prosumers) and, to cover the DSO costs, the volumetric fee, as well as the fixed fee for scenario 3 must be increased by the regulator. Fig. 4 shows that the overall cost of electricity increases by around 30% at the end of the 10 periods for traditional consumers. These consumers have to bear a larger proportion of the grid costs. As this upward change in tariff makes investing in a PV installation even more favorable to potential prosumers, the financing of the DSO is not sustainable and we can observe what is traditionally referred to as the utility death spiral.

Introducing either a prosumer or a uniform fixed fee aims at decreasing the volumetric component of the distribution tariff, and hence the benefit of net-metering. Consequently, solar PV installations are less attractive and the rate of investment is, by and large, lower, as seen in Fig. 2. In Fig. 3, a similar trend is observed for the installed capacity of PV. In the NM_{fee} scenario, the fee does not apply to the historical installations but only to the new ones, which implies that the initial tariff is equal to the tariff in the baseline scenario. In this case, the distribution tariff increases less compared to the benchmark (see Fig. 4) because, on the one hand, there are fewer PV installations, and, on the other, prosumers pay a fixed fee that partially compensates the loss of revenue of the DSO due to the meter rolling backward.

The prosumer fee reduces the rate of investment by prosumers. In the baseline scenario, over 80% of the potential prosumers have invested after two periods while in the NM_{fee} scenario, less than 30% have made such an investment. By the end of the simulation horizon, in the NM_{fee}

Table 2
Simulated scenarios.

Number	Scenarios	NM/NP	Tariff structure
#1	Baseline	NM	Vol (100%)
#2	NM_{fee}	NM	Vol(100%) + prosumer fee (85 €/kWh)
#3	NM_{fix}	NM	Vol (70%), Fix (30%)
#4	NM_{cap}	NM	Vol (50%), Cap (50%)
#5	NP_{vol}	NP	Vol (100%)
#6	NP_{cap}	NP	Vol (50%), Cap (50%)

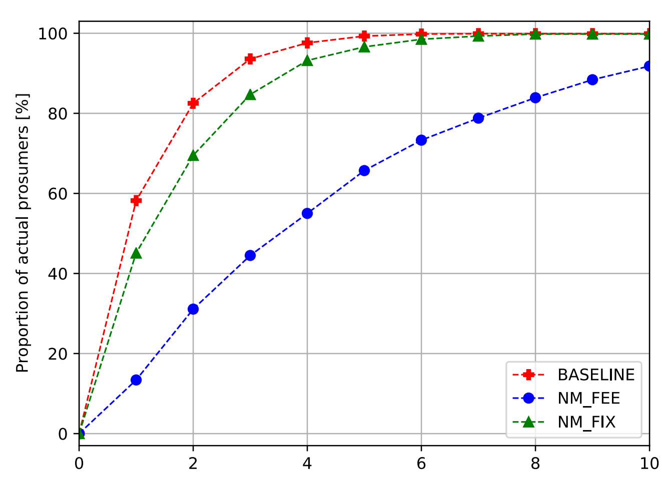

Fig. 2. Evolution of the share of prosumers among potential prosumers.

[7] We will focus on distributional issues between prosumers and traditional energy users. However, as, on average, low income consumers tend to consume less electricity, increasing the fixed part of the bill can be detrimental to low income consumers, who are also less likely to invest PV as they are typically tenants and face a binding financial constraint. This other dimension of the distributional issue can be problematic especially in the scenario NM_{fix}. However, as discussed in Burger et al. (2020), it is possible to design fixed charges based on demand characteristics or income to mitigate the regressiveness related to fixed charges.

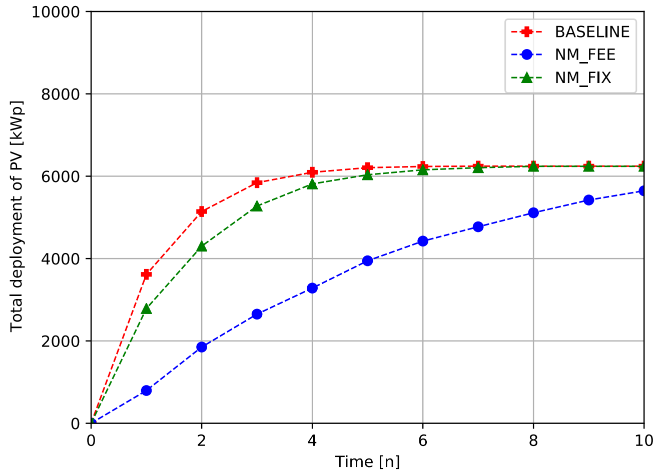

Fig. 3. Evolution of the installed capacity of PV installations.

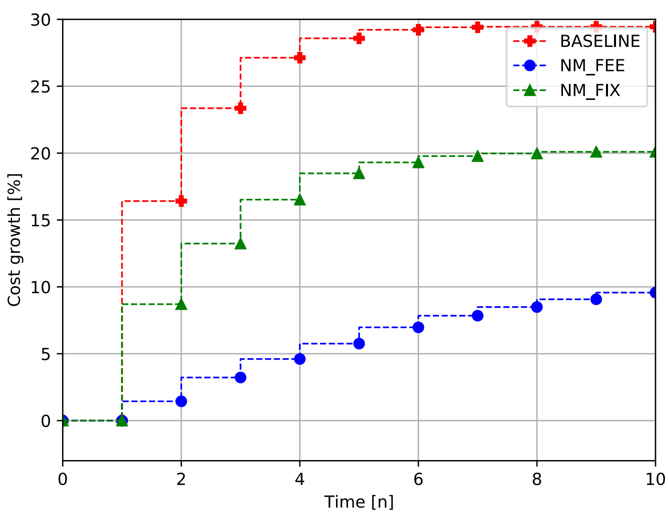

Fig. 4. Evolution of the total tariff bill of a consumer.

scenario, 90% of the potential prosumers have invested. This value, although similar to that of the baseline scenario, requires about six or seven periods more than the baseline scenario. Note that with an increase in potential prosumer population, the final values for both scenarios would tend to differ more. Finally, the introduction of a uniform fixed fee (NM_{fix}) hardly has an impact on the deployment of PV installations and simply serves as a re-distributive tool to share the grid costs between prosumers and traditional consumers differently.

The key driver of these results is that the prosumer fee substantially increases the LVOE of PV installations, as pictured in Fig. 5. Especially, we can observe that, under the NM_{fee} scenario, the mean cost is 81% higher than in the benchmark baseline scenario. With a uniform fixed fee, as in the NM_{fix} case, the mean increase is limited to 27%. The corollary is that the cost for non-prosumers is lower in the NM_{fee} and NM_{fix} scenario compared to our benchmark case. Hence, the cross-subsidization of prosumers by traditional consumers via the grid financing system is lower than in our benchmark case.

The following point still needs mentioning: in none of the three scenarios do we observe the deployment of batteries. Under net-metering, the grid acts as a giant storage facility since exporting electricity and storing it into a battery offers the same monetary value. In fact, deploying a battery will make the users lose some energy owing to

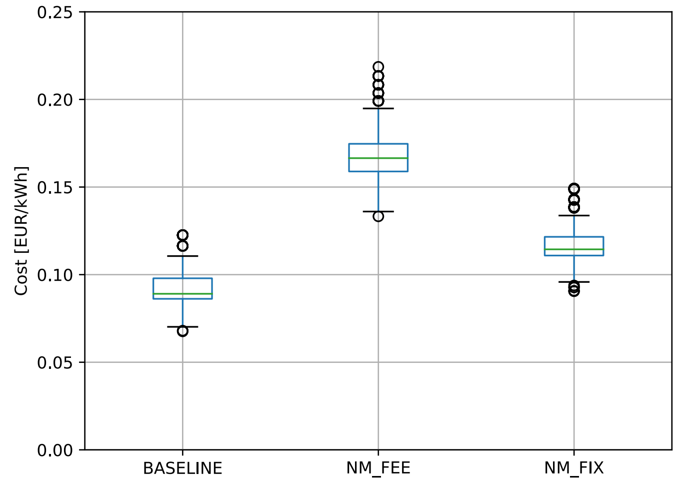

Fig. 5. Evolution of the LVOE of PV installations.

the round-trip efficiency of batteries. In such a setting, residential batteries offer no added value to this kind of investment, given that the price of electricity consumed and sold is the same.

6. Long-term reforms

Other metering technologies, like the installation of an additional meter to record the energy exported to the grid or a smart meter, allow for a larger set of feasible tariffs for financing the grid. They allow to price differently the imports and exports of energy. Smart meters can measure and record energy consumption not only on a yearly basis but also in short intervals, such as every 15 min, and be remote-controlled. As a consequence, they can record the peak consumption over the short interval measured (the shorter the interval, the more accurate the measurement).

We consider two kinds of structural regulation taking advantage of these metering technologies. The first one looks into changing the tariff structure and allowing for capacity fees in addition to the traditional fixed and volumetric distribution tariff fees. The second one looks into the possibility of switching from a net-metering to a net-purchasing system.

With net-metering, imports and exports of electricity are not differentiated in terms of prices. Hence, there is no monetary incentive to self-consume and, as shown above, prosumers do not invest in residential batteries. By measuring electricity imports and exports separately, a net-purchasing system makes it possible to differentiate the prices of the two flows. This, in turn, changes the incentives to invest both in solar PV and storage systems. Furthermore, consumers may adapt their behavior to increase their self-consumption, e.g. by shifting demand to synchronize consumption and production.

In the net-purchasing case, we consider that the price of exported electricity is equal to the average of the wholesale electricity price (around 40 €/MWh) and there is no distribution fee collected on exported electricity.[8] The electricity imported by prosumers is charged at the same price as for traditional consumers.

[8] Increasing the purchasing price of electricity above the wholesale price increases the incentives to invest in a PV installation, but decreases the incentives to invest in a battery. With a purchasing price equal to the retail price, the net-purchasing scenario would be equivalent to the baseline scenario. At least, this would be so provided that the amount of electricity that can be exported is capped to the level of electricity consumed on a yearly basis.

6.1. Net-metering system with a capacity component

In the NM_{cap} scenario, the distribution tariff is half composed of a volumetric fee and half of a capacity fee. The capacity fee is based on the peak consumption (in kWp) recorded during the billing period. With a capacity fee, a battery can be used to shave the peak consumption by displacing consumption from peak to off-peak hours. This investment may drastically reduce the prosumers' bills. In this scenario, prosumers are still connected to the grid via the net-metering technology.

As shown in Figs. 6 and 7, the change in the tariff structure only slightly curbs the deployment of solar PV compared to the fully volumetric case presented in our benchmark baseline scenario. A major difference is that we now observe the deployment of batteries (see Fig. 8). This evolution, however, is rather limited in size and is only observed from period five on (due to lower technology costs and increasing volumetric charges). While the presence of a net-metering system provides no incentive to invest in batteries, we observe that batteries enable prosumers to shave their peak production, i.e. to decrease their electricity bill, which is partially capacity based.

Compared to our benchmark, the capacity fee scenario (NM_{cap}) increases the LVOE for prosumers, but to a relatively lesser extent than when a prosumer fee is implemented, as considered under the NM_{fee} scenario (see Figs. 5 and 9). In Fig. 10, the electricity tariff paid by traditional consumers increases almost in the same proportion as in the baseline scenario. This can be explained by the fact that non-prosumers do not have the possibility to displace their peak production by using batteries. Therefore we observe, as in the benchmark, that a larger fraction of the grid costs are paid by non-prosumers.

6.2. Net-purchasing system

A net-purchasing system can be implemented by the installation of an extra mechanical meter or of a smart meter. We consider two scenarios: a fully volumetric distribution tariff (NP_{vol}), and a tariff combining capacity and volumetric terms (NP_{cap}) with an equal contribution of the two components to the grid costs. The latter is only possible in the presence of a smart meter. Thus, the tariff structure of NP_{vol} is the same as in the baseline scenario and the one of NP_{cap} is the same as in scenario NM_{cap}.

In Figs. 6 and 7, we observe that the two net-purchasing scenarios lead to a lower number of PV installations than under any net-metering system. At the end of the 10 periods considered, we find that 79% and 85% of the potential prosumers have become actual prosumers under the NP_{vol} and NP_{cap} scenarios, respectively. The growth trend of the investments made is constant and similar across the 10 periods considered. In terms of deployed PV capacity, both scenarios display a similar total installed capacity. This is because a volumetric tariff induces a larger average installation size but fewer installations.

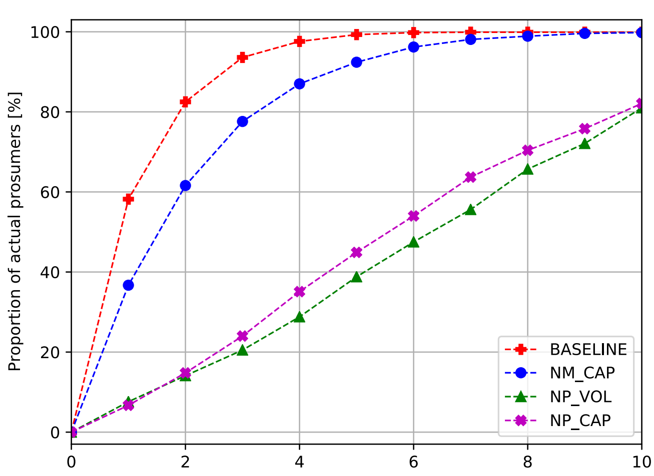

Fig. 6. Evolution of the share of households with a PV installation.

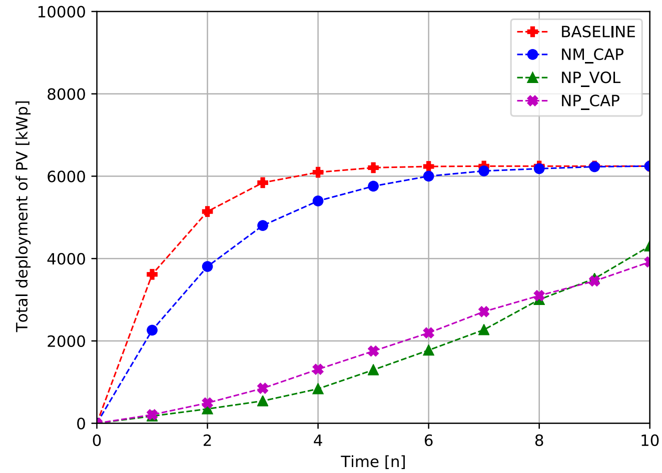

Fig. 7. Evolution of the installed capacity of PV installations.

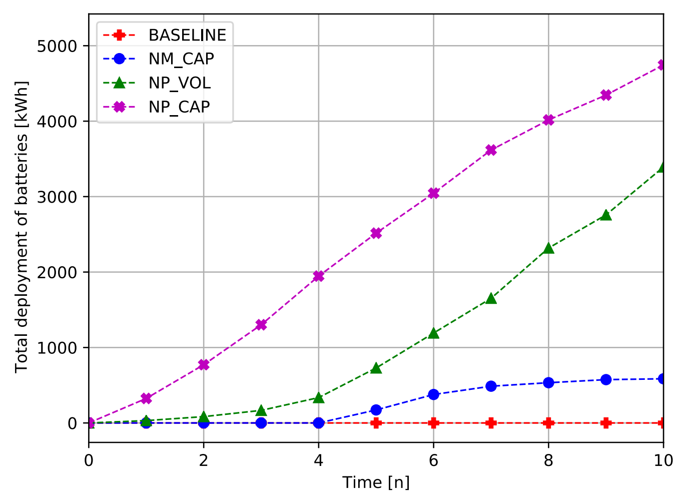

Fig. 8. Evolution of the deployment of batteries.

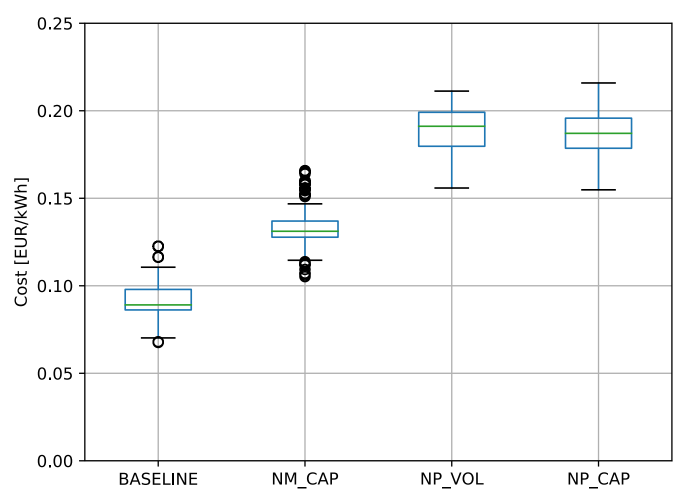

Fig. 9. Evolution of the LVOE of PV installations.

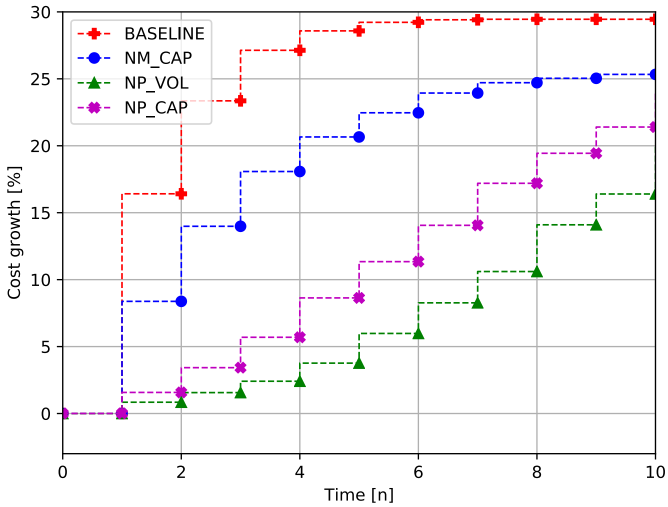

Fig. 10. Evolution of the total tariff bill of a consumer.

The high deployment of batteries is another key difference between the net-metering and the net-purchasing scenarios, as Fig. 8 shows. Under the NP_{vol} scenario, over 3000 kWh of batteries are installed, while under the NP_{cap} scenario 5000 kWh of storage capacity is available. In addition to a slightly lower LVOE under the NP_{cap} scenario than under the NP_{vol} scenario (see Fig. 9), the different reasons behind the decision of investing in batteries explain the differences in the number and size of the batteries installed in these two scenarios. Under NP_{vol}, batteries are installed because, financially speaking, it is more advantageous to store (and later consume) electricity than to sell it to the grid at selling price and later consume it at retail price. Under NP_{cap}, in addition to the previous reasons, there are additional incentives to invest in storage as batteries help reduce the electricity bill by shaving the peak demand. This behavior, moreover, is rational and relatively simple to explain from the prosumer standpoint.

Overall, switching to a new metering technology that differentiates the price of electricity imports and exports (i.e. net-purchasing instead of net-metering), as well as switching to distribution tariffs based partially on capacity components, leads to a lower amount of PV installations. This change can slow down our transition to a decarbonized energy system. However, the diffusion of panels is more even out over the years. The extent of the cross-subsidization of prosumers by traditional users via the financing of the grid is less present. Prosumers, besides, are far more likely to invest in storage devices such as batteries, and the more so when capacity fees are in place. Finally, it is important to mention that the net-purchasing system offers an additional degree of freedom by making it possible to adapt the selling price of electricity. In our work, we have considered a rather small selling price, set at the commodity price (average wholesale market price). Choosing a higher selling price makes it possible to encourage more PV investments. This, though, would induce lower investments in storage devices and an increasingly unequal electricity bills between prosumers and consumers.

6.3. Self-consumption and power exchanges with the grid

Finally, for each scenario, we compute the average self-consumption rate. The share of self-consumed electricity corresponds to the total consumption minus the imports from the grid divided by the total consumption. By increasing self-consumption, peak consumption from the centralized energy system can decrease, which is known as being one of the main drivers of the grid costs (Passey et al., 2017). Promoting self-consumption is also important because power injections to the distribution network might be costly. Indeed, as production is correlated locally, there may be large power injections made by several prosumers at the same time in the same low-voltage feeder, e.g. at noon on a holiday weekend, when decentralized production is high and consumption low. These power injections may cause over-voltages on the local distribution network, and the inverters to disconnect the solar PV from the network, inducing a loss for the prosumers. Furthermore, owing to prosumers' excessive electricity injection, the DSOs might need to reinforce the distribution network, in which context self-consumption reduces the overall costs of the DSO. These investments might require new on-load tap changers, booster transformers, and static volt ampere reactive control compensator (IEA-RETD, 2014). Hence, while self-consumption is not necessarily a goal in itself, it can be beneficial for the grid by decreasing peak consumption from the grid and peak injection to the grid.

The self-consumption rate is usually lower for residential households than for commercial activities (Clastres et al., 2019). Moreover, there is a high discrepancy in Wallonia between production and consumption: in the summer months, production is the highest and consumption the lowest and conversely in the winter months. Despite the lack of financial incentives, around 40% of prosumers claim to take actions to synchronize their consumption and production. According to Gautier et al. (2019), this is mainly true for those who tend to spend more time during daytime at home as, for instance, retired people.

We do not explicitly model the impact of self-consumption, via a change in aggregated peak consumption and injection, on the grid costs. Nevertheless, we compute the self-consumption rate for each of the six scenarios and the corresponding peak power withdrawals and injections. Focusing only on prosumers, we measure these two variables as the maximum aggregated amount of electricity withdrawn or injected over a 1 h period among the yearly profile. Table 3 presents the figures. It shows that the net-metering system does not promote self-consumption; all three net-metering scenarios present a self-consumption rate close to 30%. Aggregated peak power withdrawals and injections are marginally differing, except for the NM_{cap} where lower peak power withdrawals are observed due to the capacity component (peak shaving behaviors).

A switch to the net-purchasing system implies an increase in the self-consumption rate from 30% to 46–50%, which can easily be explained by the presence of batteries. As a consequence of promoting self-consumption, aggregate peak power withdrawals and injections are also decreasing. Under the NP_{vol} scenario, the two peaks decrease by respectively 0.76% and 4.62% compared with the baseline scenario. When coupled with a capacity component, a net-purchasing system is able to decrease the peaks more substantially by 64.2% and 18.95% (withdrawals and injection, respectively).

Hence, a net-purchasing system with capacity-based tariffs can substantially decrease the grid costs by shaving the import and export peaks. Compared to the baseline scenario, the peak demand and the peak injection decrease by respectively 60% and 19%. In the present paper these metrics can be measured only from a physical standpoint, with no associated monetary value of the reduction in the grid costs. Note, however, that these gains are possible thanks to private in-

Table 3
Self-consumption and aggregate power exchanges.

Scenarios	Absolute value	Self-consumption Rate	Peak Power withdrawals	Peak Power injections
baseline	1776.89 kWh	29.67%	2806.90 kW	4975.55 kW
NM_{fix}	1780.35 kWh	29.72%	2805.65 kW	4975.55 kW
NM_{fee}	1775.98 kWh	29.65%	2808.54 kW	4975.55 kW
NM_{cap}	1623.91 kWh	27.11%	2682.68 kW	4967.99 kW
NP_{vol}	2809.44 kWh	46.91%	2784.24 kW	4745.83 kW
NP_{cap}	2997.92 kWh	50.05%	1004.53 kW	4032.66 kW

vestments into batteries rather than a collective effort from the DSO. Those cost reduction for the DSO could be passed through consumers under the form of a lower grid tariff. Under this NP_{cap} scenario, these financial investments made by prosumers are estimated at around one million euros. If this figure from our model is extrapolated to the size of Wallonia, we have that households' investments in batteries will amount to 600 million euros to reduce grid costs. Overall, to judge the efficiency of the tariffs we would need to balance more precisely these private investments made by prosumers into batteries and the reduction in grid costs they create.

7. Conclusion and policy implications

This study has aimed to assess the impact of various tariff regulations and metering technologies on the evolution of the electricity system and, in particular, the electricity distribution network in a case study applied to Wallonia, the southern region of Belgium. Findings expressed in comparison to the baseline scenario (describing the current situation in Wallonia) are summarized in Table 4. They suggest that choosing between a net-metering and a net-purchasing technology to measure the imports and exports of electricity from/to the distribution network is critical. The net-metering system highly enhances the adoption of PV installations, which is one of the primary energy targets in the European Union, compared to the other scenarios. However, this comes at a cost. Regardless of the distribution network tariff structure considered, net-metering does not incentivize investments in battery installations at all and, therefore, does not encourage self-consumption. Peak power withdrawals and injections are decreased under a net-purchasing system, in particular when capacity-based fees are applied. Net-purchasing and capacity-based tariffs tend to strongly complement each other. Moreover, the net-metering technology leads to largely differing electricity bills for prosumers and non-prosumers, where non-prosumers end-up bearing most of the costs of the DSO. This issue can potentially impair the acceptance of electricity generation technologies coming from renewable energy.

7.1. Policy implications

The CWaPE, the energy regulator in Wallonia, pursues various objectives relating to: (i) economic efficiency, (ii) equity, and (iii) the stability of the revenues of the DSO; moreover, the CWaPE aims at (iv) designing distribution tariffs that pave the way for the energy transition. Where the net-metering technology is in place, only the latter objective is partially fulfilled as it encourages large investments in PV production sources. This situation, however, is unsustainable as the network costs are financed by non-prosumers who see their electricity bills increase. The goal of the regulator is not to financially support investments in renewable production sources but to facilitate the energy transition via regulations targeting the DSO. As other tariff regulations only marginally change these results, our analysis leads us to conclude that a net-purchasing system should be adopted. If, in addition, a capacity component is introduced in the tariff, less investments would be required to reinforce the grid as such a system substantially decreases peak power withdrawals and injections. As these changes would require smart meters, we highlight the need to deploy this technology more urgently than currently planned by the regulator. This would shorten the gap between short and long run policies, the latter of which enables the implementation of more adequate regulations.

Table 4
Summary of the results (evolution compared to the baseline scenario).

	NM_{fix}	NM_{fee}	NM_{cap}	NP_{vol}	NP_{cap}
PV adoption	=	–	–	- -	- -
Battery installations	=	=	+	++	++
Energy cost for non-prosumers	–	- -	- -	- -	- -
Peak power withdrawals/injections	=	=	–	–	- -

One reason for the relatively high electricity bills in Wallonia is that they do not only cover the costs of the commodity and the distribution network. The bills also charge users for various public policies, such as subsidies for investments in renewable energy production sources, reduced energy prices for precarious households, for the financing of public lighting, or the costs of the planned nuclear phase-out (CWaPE, 2020). As distribution tariffs are computed on a volumetric basis, considering these additional costs to compute the electricity bills makes the system even less sustainable financially and prone to un-even allocation of those additional costs where prosumers may end up not paying for public services such as lighting. All these public policies should be financed by the public finance system. This, in addition, would be a much more transparent and democratic procedure as they would fall under parliamentary oversight. Changing the financing sources of these policies would decrease the pressing concerns of a utility death spiral and equity issues between prosumers and traditional consumers.

Finally, this analysis shows the importance of designing holistic policies supporting PV adoption and regulating the electricity distribution network, both concerning tariffs and metering technology, so as to facilitate a sustainable energy transition.

7.2. Limitations and future research

Our model relies on various assumptions relating to prosumers and the grid, which could influence some of our results. Yet, we believe that extending the model to consider these assumptions would lead to qualitatively similar results. To fully examine them, future research will be needed.

In our model, potential prosumers are presumed to choose to invest in a PV installation or in both a PV and a battery installation. As a consequence, early PV adopters do not have the opportunity to later invest in an additional battery system. Allowing for this possibility would not impact the scenarios considered in the short run, i.e. where a net-metering system is in place, as anyway no investment in batteries is done. However, in the net-purchasing cases considered in the long run, both investments in PV and in batteries would increase. Changing this assumption would further strengthen the main conclusion of our analysis.

Our model considers a wide, yet for simplicity's sake, fixed variety of consumption load profiles. It is unlikely, though, that they will not evolve over time. For example, owing to the deployment of electric vehicles, consumption profiles are likely to change. While electric vehicles increase consumption, they also act as a storage device potentially enabling peak shaving. As the functionalities of their batteries are similar to those of an ordinary battery, considering evolving load profiles would lead to lower investments in batteries in the long run scenario with a net-purchasing system or a net-metering system with tariffs with a capacity component. The ensuing higher consumption levels would lead to a greater deployment of PV installations along with even larger rebates on the energy bill. Overall, taking these aspects into consideration would not qualitatively impact the key insights of the current simulator.

One final limitation deserves to be mentioned. In this paper, we model the financing of the network grid as a zero-sum game. Further, we have shown that some grid regulations, and especially capacity tariffs coupled to a net-purchasing system, lead to a decrease in peak power imports and exports. These collective benefits can be translated into lower grid costs that are possible thanks to the private investments into batteries by prosumers. We hope that further research will allow a more precise quantification and comparison of these aspects.

CRediT authorship contribution statement

Miguel Manuel de Villena: Methodology, Software, Validation, Formal analysis, Investigation, Data curation, Writing - original draft, Writing - review & editing, Visualization. **Julien Jacqmin:** Conceptualization, Writing - original draft, Writing - review & editing, Visualization, Supervision. **Raphael Fonteneau:** Methodology, Software, Validation, Investigation, Supervision. **Axel Gautier:** Conceptualization, Methodology, Writing - original draft, Writing - review & editing, Supervision, Project administration, Funding acquisition. **Damien Ernst:** Investigation, Resources.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix

The tariff simulator used in this paper is composed of three elements: (i) an optimization framework to size prosumers' installations comprising PV and/or batteries; (ii) an investment decision process that controls the decision of prosumers to deploy the optimally sized DER installation; and (iii) the remuneration mechanism that computes costs and revenues of the DSO and adjusts the distribution network tariff accordingly.

Optimization framework

This element of the tariff simulator is used to optimally size prosumers' DER installations according to various input parameters, notably the network tariff structure and network rates (e.g. 100% volumetric fee at 23c€kW), the technology costs (price of the PV panels and the batteries per kWp and kWh respectively), or selling price of electricity surplus. This optimization framework is instantiated in the form of a mixed integer linear program (MILP) where the binary variables are used to control the piecewise linear investment costs as well as the battery mode (charge or discharge). Such an MILP minimizes the LVOE of each prosumer's DER installation, and finds the optimal sizing configuration in terms of PV and battery capacities. The formulation is laid out in the following way:

Given the space of sizing variables $\mathscr{A} = \{(p,b) \big| p \in [0,\overline{p}]; b \in [0,\overline{b}]\}$ denoting the space of sizing variables containing: PV size (p) in kWp, battery size (b) in kWh; with $\overline{p}$, and $\overline{b}$ being parameters denoting the upper bounds on PV and battery capacities, respectively.

$$\min_{A \in \mathscr{A}} \quad \frac{\chi + \sum_{y=0}^{Y-1} \frac{\upsilon_y + \psi_y + m_y - \zeta_y}{(1+r)^y}}{\sum_{y=0}^{Y-1} \frac{\sum_{t=0}^{T-1} U_t^{(c)}}{(1+r)^y}} \tag{1}$$

subject to:

$$\zeta_y = \sum_{t=0}^{T-1} \rho_t^{(+)} \cdot \Pi^{(sp)}, \ \forall y \in \mathscr{Y} \tag{2}$$

$$\chi = p \cdot P^{(pv)} + \frac{Y}{B} \cdot b \cdot P^{(bat)} + \tau^{(pv)} \cdot Q^{(pv)} + \tau^{(bat)} \cdot Q^{(bat)} \tag{3}$$

$$p \leq \overline{p} \cdot \tau^{(pv)} \tag{4}$$

$$b \leq \overline{b} \cdot \tau^{(bat)} \tag{5}$$

$$\upsilon_y = \xi_y \cdot \Pi^{(vol)} + \gamma \cdot \Pi^{(cap)} + \Pi^{(fix)}, \ \forall y \in \mathscr{Y} \tag{6}$$

$$\psi_y = \xi_y \cdot \Pi^{(ot)}, \ \forall y \in \mathscr{Y} \tag{7}$$

$$m_y = \frac{1}{200} \cdot p + \frac{1}{100} \cdot b, \ \forall y \in \mathscr{Y} \tag{8}$$

$$\xi_y = \sum_{t=0}^{T-1} \rho_t^{(-)}, \ \forall y \in \mathscr{Y} \tag{9}$$

$$\rho_y^{(-)} \leq \gamma \leq U_t^{(c)}, \ \forall t \in \mathscr{T} \tag{10}$$

$$k_t = p \cdot U_t^{(p)}, \ \forall t \in \mathscr{T} \tag{11}$$

$$j_t^{(-)} \leq b \cdot \frac{1}{F^{(-)}}, \ \forall t \in \mathscr{T} \tag{12}$$

$$j_t^{(+)} \leq b \cdot \frac{1}{F^{(+)}}, \ \forall t \in \mathscr{T} \tag{13}$$

$$j_t^{(-)} \leq \overline{b} \cdot \sigma_t, \ \forall t \in \mathscr{T} \tag{14}$$

$$j_t^{(+)} \leq \overline{b} \cdot (1 - \sigma_t), \ \forall t \in \mathscr{T} \tag{15}$$

$$U_t^{(c)} + \rho_t^{(+)} + j_t^{(+)} = k_t + \rho_t^{(-)} + j_t^{(-)},\ \forall t \in \mathscr{T} \tag{16}$$

$$\varpi_t \leq b,\ \forall t \in \mathscr{T} \tag{17}$$

$$\varpi_t = \begin{cases} \varpi_{t-1} - \dfrac{j_t^{(+)}}{\eta^{(+)}} + j_t^{(-)} \cdot \eta^{(-)}, \forall t \in \mathscr{T} \backslash \{0\} \\ 0 \text{ if } t = 0 \end{cases} \tag{18}$$

where:

Sets	
$\mathscr{T}$	Set of time-steps comprising each year of the optimization with $t \in \{0, \ldots, T-1\}$
$\mathscr{Y}$	Set of years comprising the optimization horizon with $y \in \{0, \ldots, Y-1\}$
Parameters	
$Q^{(pv)}$	Deployment costs of PV
$Q^{(bat)}$	Deployment costs of battery
$P^{(pv)}$	Scaling costs of PV per kWp installed
$P^{(bat)}$	Scaling costs of battery per kWh installed
Π^{ot}	Sum of energy and transission costs, and taxes in €/kWh
Π^{sp}	Selling price of electricity surplus for prosumers €/kWh
Π^{vol}	Volumetric term of the distribution tariff €/kWh
Π^{cap}	Power (capacity) term of the distribution tariff €/kWp
Π^{fix}	Fixed term of the distribution tariff €/consumer
$\eta^{(-)}$	Battery charge efficiency
$\eta^{(+)}$	Battery discharge efficiency
$F^{(-)}$	Battery maximum charge rate
$F^{(+)}$	Battery maximum discharge rate
B	Battery lifetime in years
$U_t^{(c)}$	Time-series of consumption
$U_t^{(p)}$	Time-series of production
$\overline{p}$	Maximum PV potential per prosumer
$\overline{b}$	Maximum battery potential per prosumer
R	Discount rate
Decision variables	
P	PV capacity deployed in kWp
B	Battery capacity deployed in kWh
X	Investment costs of a single DER installation
$\rho_t^{(-)}$	Imports of energy of a prosumer
$\rho_t^{(+)}$	Exports of energy of a prosumer
ξ_y	Yearly energy consumption of a prosumer in kWh
Γ	Peak demand of a prosumer in kWp
υ_y	Yearly distribution costs
ψ_y	Yearly transmission and taxes costs
m_y	Yearly operation and maintenance costs
k_t	PV output of a prosumer in Kw
$j_t^{(-)}$	Energy flow into the battery
$j_t^{(+)}$	Energy flow out of the battery
ϖ_t	State of charge of the battery
ζ_y	Revenue of a prosumer from electricity surplus sales
Auxiliary variables	
$\tau^{(pv)}$	Binary variable enforcing the deployment costs of PV
$\tau^{(bat)}$	Binary variable enforcing the deployment costs of battery
σ_t	Binary variable controlling the status –charging or discharging– of the battery

Investment decision process

The previous MILP is run for each of the potential prosumers in the set $\mathscr{I} = \{1, \ldots, I\}$, at each time-step of a dynamical system denoted by $\mathscr{N} = \{0, \ldots, N-1\}$. This MILP returns the LVOE of each potential prosumer, which is the objective function, as well as the optimal sizing configuration leading to this LVOE, given the input parameters specified previously. For an accurate description of these parameters the reader is referred to Manuel de Villena et al. (2021). For simplicity, let *MILP*(inputs) denote the general objective function of the MILP presented in the previous section, depending on the inputs. Then, for every potential prosumer i at each time step n we have:

$$LVOE_{i,n} = \min_{\substack{A \in \mathscr{A} \\ s.t.(2)-(18)}} MILP(\text{inputs}), \forall (i,n) \in \mathscr{I} \times \mathscr{N} \tag{19}$$

$$A^*_{i,n} = \underset{\substack{A\in\mathscr{A} \\ s.t.(2)-(18)}}{\arg\min} \quad MILP(\text{inputs}), \forall(i,n)\in\mathscr{I}\times\mathscr{N} \tag{20}$$

where $LVOE_{i,n}$ represents the LVOE of prosumer i at time-step n and $A^*_{i,n}$ represents the optimal sizing configuration of PV in kWp and battery in kWh leading to this LVOE for these input parameters.

The investment decision process is run for each potential prosumer to compute the transition from potential to actual prosumer. This computation requires comparing the electricity costs per kWh of the prosumer with and without DER installation, for some level of distribution tariff. The electricity costs per kWh with the DER installations is the LVOE, the electricity costs per kWh without the installation, denoted $\Lambda_{i,n}$ can be computed according to the following equation:

$$\Lambda_{i,n} = \Pi^{(ot)}_n + \Pi^{(vol)}_n + \frac{\gamma^{(o)}_{i,n}\cdot\Pi^{(cap)}_{i,n} + \Pi^{(fix)}_n}{\sum_{t=0}^{T-1} U^{(c)}_{i,n,t}}, \forall(i,n)\in\mathscr{I}\times\mathscr{N}, \tag{21}$$

where $\Pi^{(ot)}_n$ represents the sum of transmission costs and taxes at time-step n, $\Pi^{(vol)}_n$ represents the volumetric term of the network tariff at time-step n, $\Pi^{(cap)}_{i,n}$ represents the capacity term of the network tariff for user i at time-step n, $\Pi^{(fix)}_n$ represents the fixed fee at time-step n, $\gamma^{(o)}_{i,n}$ is the original peak demand of the user, and $U^{(c)}_{i,n,t}$ is the hourly (assuming that $T = 8760$) demand of potential prosumer i at time-step n.

Then, $LVOE_{i,n}$ and $\Lambda_{i,n}$ can be compared, computing the ratio $\Gamma_{i,n}$:

$$\Gamma_{i,n} = \frac{LVOE_{i,n}}{\Lambda_{i,n}}, \forall(i,n)\in\mathscr{I}\times\mathscr{N}. \tag{22}$$

In this equation, $\Gamma_{i,n}$ will adopt a value in $[0,1]$ since $\Lambda_{i,n}$ must be strictly positive assuming the aggregated demand of the potential prosumer is strictly positive, and since $LVOE_{i,n}$ cannot be greater than $\Lambda_{i,n}$ by design of the MILP. The continuous value of $\Gamma_{i,n}$ is then introduced to bias the value of the parameter $p_{i,n}$ of a Bernoulli random variable $B(1,p_{i,n})$ such that:

$$p_{i,n} = \left(\left(1-\alpha\cdot\Gamma_{i,n}\right)\middle|\alpha\in[0,1]\right), \forall(i,n)\in\mathscr{I}\times\mathscr{N}, \tag{23}$$

where α is the exogeneous probability mentioned in Section 4.1, which is calibrateded to ensure that 1€cent induces an investment in PV of 8% as observed in Gautier and Jacqmin (2020).

Finally, we can draw a random variable $\beta_{i,n}\in\{0,1\}$ for every potential prosumer at every time-step n.

$$\beta_{i,n} \sim B\left(1, p_{i,n}\right), \forall(i,n)\in\mathscr{I}\times\mathscr{N}. \tag{24}$$

The value of this variable will be either 0, indicating that the potential prosumer will not deploy the DER installation, or 1, indicating that the potential prosumer will deploy it, turning into an actual prosumer. The probability of randomly selecting 1 will directly depend on the ratio $\Gamma_{i,n}$ – if the ratio is close to 1, the probability $p_{i,n}$ of drawing 1 will be low, and conversely, if the ratio is close to 0, the probability of drawing 1 will be high. After all potential prosumers have been evaluated through the investment decision process, the set $\mathscr{I}$ is updated so that:

$$\mathscr{I} = \mathscr{I}\setminus\left\{i\middle|\beta_{i,n}=1\right\}. \tag{25}$$

Remuneration mechanism

At every time-step n, the DSO remuneration mechanism ensures that any economic imbalances are translated into a network tariff adjustment. To that end, the revenue of the DSO R_n are computed according to the following expression:

$$R_n = \left[\Pi^{(vol)}_n\cdot(\Omega+\Xi_n)\right] + \left[\Pi^{(cap)}_n\cdot\sum_{i=1}^{(I+I_0)}\gamma_{i,n}\right] + \left[\Pi^{(fix)}_n\cdot(I+I_0)\right] \quad \forall n\in\mathscr{N}, \tag{26}$$

where I_0 represents the consumers (i.e. non prosumers) of the distribution network. $\gamma_{i,n}$ represents the optimised peak demand of the i^{th} user, output of the MILP. Ω represents the residual demand of the system, which is an input of the simulation and is held constant throughout the entire simulation process. Finally, Ξ_n represents the aggregated consumption of the agents in $\mathscr{I}$, computed as:

$$\Xi_n = \sum_{i=1}^{I}\rho^{(-)}_{i,n} \quad \forall n\in\mathscr{N}, \tag{27}$$

where $\rho^{(-)}_{i,n}$ represents the optimised imports of the i^{th} potential or actual prosumer at the n^{th} time-step, which is an output of the MILP.

Assuming that the demand of consumers and prosumers is constant over time, at the beginning of the simulation, the revenue can be computed R_{-1}, as there are no actual prosumers in the system. This level of revenue is assumed to cover DSO costs without any economic imbalance (i.e. revenue equals costs). Thus, the costs, denoted Θ_n are assumed equal to the revenue at the beginning of the simulation ($\Theta_{-1} = R_{-1}$). However, as potential prosumers gradually turn into actual prosumers, an imbalance Δ_n emerges on account of the energy not paid by actual prosumers. This imbalance is computed as:

$$\Delta_n = \Theta_n - R_n, \forall n\in\mathscr{N}. \tag{28}$$

Then, the different components of the distribution network tariff are updated according to the following equations:

$$\Pi_{n+1}^{(vol)} = \left[\frac{\Theta_n + \Delta_n}{\Omega + \Xi_n}\right] \cdot \mu_1 \quad \forall n \in \mathcal{N}, \tag{29}$$

$$\Pi_{n+1}^{(cap)} = \left[\frac{\Theta_n + \Delta_n}{\sum_{i=0}^{(I+I_0)} \gamma_{i,n}}\right] \cdot \mu_2 \quad \forall n \in \mathcal{N}, \tag{30}$$

$$\Pi_{n+1}^{(fix)} = \left[\frac{\Theta_n + \Delta_n}{I + I_0}\right] \cdot \mu_3 \quad \forall n \in \mathcal{N}. \tag{31}$$

In these equations, μ_1,μ_2, and μ_3 represent the share of the volumetric, capacity, and fixed fee, respectively, imposed by the DSO's remuneration strategy, and therefore by the regulatory framework set by the regulator. These shares comply with $\sum_{j=1}^{3} \mu_j = 1$. Finally, to compute the costs Θ_n we assume that the last observed state is conserved from n to $n+1$, and then updated. Hence, $\Theta_n = R_{n-1}$, where R_{n-1} is recomputed at every n according to equation (26).

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