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Abstract

Traditional analysis of distribution grid user's reaction to tariffs assumes a low price sensitivity and a lack of alternative technologies to grid connection. This is radically changing with two technology breakthroughs: (1) Photovoltaics (PV) enable domestic and commercial consumers to self-produce energy; (2) Batteries allow self-producers to set both their grid energy and capacity parameters. Contributing to the state of the art, the grid cost recovery problem is modelled as a non-cooperative game between consumers. In this game, the availability and costs of new technologies (such as PV and batteries) strategically interact with tariff structures. Four states of the world for user's access to new technologies are distinguished and three tariff structures are evaluated. The assessed distribution network tariff structures are: energy volumetric charges with net-metering, energy volumetric charges for both injection and withdrawal, and capacity-based charges. Results show that the new distribution world -open by new technology choices for grid users- is highly interactive and threatens grid regulation not understanding it.

Keywords

Batteries, bi-level modelling, distributed energy adoption, distribution network tariff design, non-cooperative behaviour

1. Introduction

The assumption that consumers connected to the distribution grid are passive does not hold true anymore. This is mainly due to the sharply decreasing costs of two technologies: photovoltaics (PV) and batteries. These two technologies allow grid users to react to the way electricity supplied by the grid is priced. PV enables consumers to self-produce energy and lowers the net energy need from the grid, while batteries enable self-producers to regulate both their grid energy flows and capacity parameters. These developments contrast the recent past, in which network tariff design did not matter much as low-voltage consumers had few substitutes for grid-supplied electricity.

Suddenly, network tariff design has become a concern. Active consumers will react with their profit-maximising actions to any network tariff charged to them. If network tariff design does not anticipate the new sets of actions available to consumers, grid revenues and cost recovery are at risk. In short, the availability and costs of new "consumer enabling" technologies interact with network tariff design; and both issues cannot be dealt with in isolation anymore.

How to re-design the distribution network tariff to deal with these new challenges? Hledik and Greenstein (2016) and Simshauser (2016) argue that capacity-based charges (in € per kilowatt (kW) peak) have emerged as an attractive option. These authors contend that capacity-based grid charges would avoid inequitable bill increase and allow for better cost reflection. However, not everyone agrees. Borenstein (2016) reasons that challenges arise as a significant part of the network costs are residual or sunk costs.[1] He states that there is no clear guidance from economic theory on how to allocate such costs as cost causation is unclear. He argues that almost surely a combination of higher fixed charges and an adder to time-varying volumetric charges would be the least bad policy option. Similarly, Brown et al. (2015) do not identify any single best option for the recovery of residual costs. They state that the recovery of residual costs through fixed charges would result from prioritising the principle of efficient prices.

In Europe and the USA there is an observable trend towards volumetric tariffs (in €/ kWh) being gradually replaced by capacity-based tariffs (CEER, 2017; European Commission, 2015; Hledik, 2015). Especially a volumetric tariff accompanied with net-metering, the network tariff design historically in place, is challenged both in the media[2] and in academic circles (e.g Darghouth et al., 2011; Eid et al., 2014). Net-metering is the practice by which consumers are accounted solely for their net electricity consumption from the grid when distribution charges are determined.

The main contribution of this paper is to represent the cost recovery problem as a non-cooperative game between consumers. The proposed game-theoretical optimisation model addresses two things simultaneously: (1) The re-design of the network tariff and; (2) The strategic reaction of consumers to the network tariff to opt out of part of the grid use. Thereby, reacting consumers, able to invest in PV and batteries, can shift sunk grid costs to passive consumers and at the same time compete to reallocate the sunk grid costs to one another. Uncoordinated investment decisions by these reactive consumers can lead to an overall efficiency loss and this dynamic is not captured by Borenstein (2016), Brown et al. (2015), Hledik and Greenstein (2016), and Simshauser (2016) who either do qualitative or static-quantitative analysis.[3]

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1 This is especially true in networks experiencing low or no load growth for which costs occurred in the past to dimension distribution grids to the expected peak capacity needed in the local system (Pérez-Arriaga and Bharatkumar, 2014).

2 E.g.: Pyper, Julia. 2015. “Ditching Net Metering Is in the ‘Best Interest’ of Solar, Say MIT Economists.” *Greentech Media*. May 05, 2015. www.greentechmedia.com/articles/read/MIT-Economists-Say-We-Should-Ditch-Net-Metering

3 DER adoption as a reaction to network tariff design is considered exogenous and ‘revenue neutrality’ for the network operator is assumed when assessing different tariff structures with a consumer database. Assuming revenue neutrality is from a modelling perspective not different than assuming grid costs are sunk.

Four states of the world are built up to capture the performance of different tariff designs under different technology cost scenarios. No "future-proof" network tariff design was identified. The findings of the pro-capacity-based camp, e.g. Hledik and Greenstein (2016) and Simshauser (2016), are nuanced. Depending on the state of the world and its implementation, also capacity-based charges can severely distort the investment decisions of consumers.

The remaining parts of the paper are structured as follows. In Section 2 the methodology of the paper is highlighted. In Section 3, the proposed model is described in detail. In Section 4, the setup of the numerical example, data and the technology scenario matrix is presented. The results are discussed in Section 5. Lastly, a conclusion is formulated and possibilities for future work are summarised.

2. Methodology: three tariff structures, two metrics and four states of the world

Three different tariff structures (TS) are analysed:[4]

- **TS1**: Volumetric network charges with net-metering.
- **TS2**: Volumetric network charges without net-metering, bi-directional metering is applied charging both energy withdrawal and injection.
- **TS3**: Capacity-based charges based on the observed individual peak power withdrawal or injection from the grid over a certain duration (e.g. hourly or quarter-hourly).[5]

The outcomes of the tariff structures are benchmarked with the application of fixed network charges. Fixed network charges serve as a reference as they do not distort the volumetric (€/kWh) and capacity (€/kW) price signal and going entirely off-grid is not considered an option for consumers in this paper. This is not a strong simplification as Hittinger and Siddiqui (2017) find that the financial case for grid defection is limited or non-existent given current costs and prevalent policies. Two metrics are introduced to quantify the results. Firstly, a proxy for (in)efficiency is used to quantify the increase of the total system cost as compared to the reference case with fixed network charges. Secondly, a proxy for equity is introduced by looking at the allocation of the sunk costs for different consumer's types under the different tariff structures.

A 'Technology costs matrix', with four extreme states of the world, is set up to analyse the impact of dropping investment costs in PV and batteries (RMI, 2015). This matrix is displayed in Table I.

Table I: Matrix representation of the four states of the world related to technology costs

Technology cost matrix		Capital cost PV (€/kW$_p$)	
		High	Low
Capital cost batteries (€/kWh)	High	The past?	Today?
	Low	Unlikely?	The future?

In the past, a consumer did not have much means to react to electricity prices as distributed energy resources (DER) were too expensive to invest in. Today, residential PV becomes more and more competitive with electricity supplied from the central grid, while batteries are still relatively expensive. Nevertheless, a scenario with low PV and battery investment costs can be expected to materialise soon as pointed out by many studies (Lazard, 2016a; MIT, 2016; RMI, 2015). As an illustration, in the Utility of the Future Study by MIT (2016) it is quoted that PV developers and

[4] No time variation in the rates is assumed, solely the 'structure or format' of the tariffs differ.

[5] Currently, in most cases, low voltage users are being billed by the contracted capacity, and not through an observed maximum capacity. However, with the envisioned mass roll-out of smart meters accurate maximum capacity charging of network users will be enabled (Eid et al., 2014).

industry analysts expect the installed cost of utility -scale PV to fall below $1000 per kW before the end of this decade[6], and that one major US automaker projects that lithium-ion battery cell costs will drop below $100 per kWh by 2022— an order of magnitude less costly than 2010 costs.[7]

3. Model: approach and mathematical formulation

In this Section, the modelling approach is presented. This Section is split up into two Subsections. The first Subsection explains the high-level functioning of the model and relevant literature. A second Subsection describes the mathematical formulation of the model.

3.1 Modelling approach

The stylised game-theoretical optimisation model presented in this work has a bi-level structure (Gabriel et al., 2012), i.e. it consists of an optimisation problem in the upper level which is linked to several individual optimisation problems at a lower level. By doing so, the 'electricity cost optimisation problem' of one consumer is impacted by decisions of other consumers. For example, under volumetric charges with net-metering, if a consumer installs PV, it would mean that the total net volume of electricity requested from the grid is reduced. Consequently, the total amount of network charges paid would reduce. In reaction, the volumetric rate of the network charge must now be increased to allow total cost recovery for the DSO. This rate increase makes it possibly interesting to install additional capacity of PV and so forth. With the formulation applied in this paper, an equilibrium is found where the sunk costs are recovered and the consumers have no incentive anymore to change their reaction to the network tariff.

The actors represented by the two levels of the model are:

- *In the upper level:* A cost-allocator, representing a simplified distribution system operator (DSO). The cost allocator in the upper level has the objective to recover its costs and sets the network charges perfectly anticipating the reaction of the lower level consumers to these charges.
- *In the lower level:* Consumers connected to the distribution grid. The consumers are split up as reactive and active consumers and have the objective to minimise their electricity costs. Reactive consumers have the possibility to invest in solar PV and batteries, while passive consumers do not. The network charges are the signal closing the loop by connecting the upper and lower level.

Many models with a similar mathematical structure have been applied to other energy related problems as can be found in the literature. Three illustrations that have inspired this paper are Zugno et al. (2013), Momber et al. (2016) and Saguan and Meeus (2014). Zugno et al. (2013) apply a bi-level model with a profit maximising electricity retailer in the upper level. The retailer buys electricity from the spot market and sells it to consumers in the lower level, which react to the dynamic retail price by shifting their load. Similarly, Momber et al. (2016) modelled a profit maximising aggregator in the upper level, which takes decisions on retail prices and optimal bidding in electricity markets, while being subjected to lower level decisions of EV owners minimising their charging schedule cost. Saguan and Meeus (2014) introduce a competitive equilibrium model to calculate the cost of

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[6] Wesoff, Eric. 2015. "First Solar CEO: 'By 2017, We'll Be Under $1.00 per Watt Fully Installed'." *Greentech Media*. June 24, 2015. www.greentechmedia.com/articles/read/First-Solar-CEO-By-2017-Well-be-Under-1.00-Per-Watt-Fully-Installed.

[7] Wesoff, Eric. 2016. "How Soon Can Tesla Get Battery Cell Costs Below $100 per Kilowatt-Hour?" *Greentech Media*. March 15, 2016. www.greentechmedia.com/articles/read/How-Soon-Can-Tesla-Get-Battery-Cell-Cost-Below-100-per-Kilowatt-Hour.

renewable energy in four states of the world, i.e. with versus without renewable trade, and with national transmission planning versus international transmission planning.

3.2 Mathematical formulation[8]

In this Subsection, the two levels of the bi-level equilibrium model and how they are connected are described in more detail. This Subsection is split up into three parts. Firstly, the upper level, representing a simplified DSO recovering its incurred costs is described. Secondly, the lower level with individual consumers connected to the distribution network is described. The consumers receive the network price signal from the upper level and are solving an optimisation problem with the minimization of their electricity cost as objective. Lastly, it is explained how the method for solving the mathematical problem in which the upper and lower level are combined, is explained.

3.2.1 Upper-level formulation

The cost recovery constraint of the simplified DSO is displayed by Equation 1. The equation states that the total network costs to be recovered are equal to the total network charges collected by the DSO to recover their costs.[9] The total network charges collected from the consumers are calculated by the right-hand side of the equation. The sunk cost assumption implies that the change in aggregated consumption/injection behaviour of the reactive consumers connected to the distribution grid does not have an influence on the total network costs to be recovered. In other words, costs occurred in the past, anticipating future usage. This assumption will be relaxed in future work.

$$\text{Network costs} = \sum_i \left[\mathrm{N_i} * \left(\alpha * vnt * \sum_t (pw_{t,i} - pi_{t,i} * \mathrm{NM}) * \mathrm{WDT} + \beta * cnt * pmax_i + (1 - \alpha - \beta) * \frac{\text{network costs}}{\mathrm{N}} \right) \right] \quad (1)$$

The parameter $\mathrm{N_i}$ stands for the number of consumers represented by representative consumer i.[10] To limit the computational time, representative consumers standing for homogenous groups are used. The variables of the upper level are vnt the coefficient of the volumetric charge in €/kWh, and cnt the coefficient of the capacity-based charge in €/kW. Depending on the tariff structure a coefficient can be forced equal to 0. Further, $pw_{t,i}$ represents the power withdrawn from the grid at time step t by consumer i, $pi_{t,i}$ the power injected into the grid at time step t by consumer i. WDT is a scaling factor for the annualization of all costs. Lastly, $pmax_i$ is the peak use of the network by consumer i. It is a proxy for the maximum capacity required to service consumer i's network requirements.

In Table II the different network tariff structures and their parameter settings are displayed. In cases where TS1 or TS2 are applied, the second term of the summation on the right-hand site of Equation 1 will equal zero as cnt is forced to zero. The third term of the equation, representing fixed network charges, will also be zero as α equals 1. By setting parameter NM to 1 the power withdrawn from the grid ($pw_{t,i}$) is netted out with the power injected into the grid ($pi_{t,i}$), representing net-metering. If NM is set to -1, no netting out takes place, and both power withdrawal and injection are subjected to network charge vnt. When applying TS3 vnt will be forced to zero and again the third term of the summation will equal zero as β is set to 1. Lastly, when fixed network charges are applied the first two terms of the summation will equal zero as α and β are set equal to zero.

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8 Variables are represented by italic lower case Latin letters, for parameters upper case Latin or lower case Greek letters are used.

9 For computational reasons an error margin δ (typically 1% of the network costs) is applied, allowing for a limited deficit or excess.

10 Alternatively, proportions of consumer groups relative to all consumers connected could be used. In that case the total network costs are scaled accordingly.

Table II:
The different network tariff options - description and parameter settings for Equation 1

	Network tariff structure	Description	α Volumetric	β Capacity	NM Net-metering
TS1	Volumetric charges with net metering	Only the net consumption is used to calculate the network charges to be paid by the consumer.	1	0	1
TS2	Volumetric charges without net metering	The sum of the withdrawal and injection into the grid is used to calculate the network charges per consumer.	1	0	-1
TS3	Capacity-based charge	The withdrawal or injection peak (in kW) measured over the length of the full-time horizon is used to calculate the network charges paid by the consumer.	0	1	0
Ref.	Fixed network charges	The fixed charge is uniform and equal to the sunk cost to be recovered divided by the number of consumers.	0	0	0

3.2.2 Lower level formulation

The objective function of a lower level consumer is presented by Equation 2. Each consumer minimises its (annualised) total cost of servicing its electricity requirements. The total costs consist of four parts; the energy costs, the network charges and other charges that constitute the electricity bill, and the investments costs in DER technology.[11] In the case where a consumer is passive, the investment costs will always be zero. For a reactive consumer, the investment costs might be non-negative. This would be the case if additional investment costs are lower than the decrease in the electricity bill due to the DER investment. With 'other charges', e.g. RES levies are meant. It is assumed that these charges are paid as a fixed fee, and do not influence the optimisation problem of an individual consumer.

$$\text{Minimise } \ energy\ costs_i + network\ charges_i + other\ charges + investment\ costs_i \tag{2}$$

With:

$$energy\ costs_i = \sum_t \left(pw_{t,i} * \mathrm{EBP_t} - pi_{t,i} * \mathrm{ESP_t}\right) * \mathrm{WDT} \tag{3}$$

$$network\ charges_i = \sum_t (pw_{t,i} - pi_{t,i} * \mathrm{NM}) * vnt * \mathrm{WDT} \ + pmax_i * cnt + \ (1 - \alpha - \beta) * \frac{\text{network costs}}{\mathrm{N}} \tag{4}$$

$$investment\ costs_i = \ is_i * \mathrm{ICS} * \mathrm{AFS} + ib_i * \mathrm{ICB} * \mathrm{AFB} \tag{5}$$

Equation 3 describes the calculation of the energy cost. $\mathrm{EBP_t}$ represents the price paid by a consumer for withdrawing one kWh of electricity at time step t from the grid, excluding the network or other charges. $\mathrm{EBP_t}$ can be thought of as the wholesale electricity price plus a retail margin. $\mathrm{ESP_t}$ stands for the price received for injecting one kWh of electricity into the grid. Depending on the country context $\mathrm{ESP_t}$ may be labelled the feed-in tariff, again excluding possible network other charges. The energy costs are annualised using a scaling factor WDT.

In Equation 4 the network charges paid by consumer i are calculated. Depending on the applied tariff structure, two of the three terms of the summation will be forced to zero. When TS1 or TS2 is applied, only the first term will be greater or equal than zero, in the case of TS3 the second term can be positive and finally when TS4 is applied the third term will be greater than or equal than zero.[12]

The investment costs of DER installed by a consumer are described by Equation 5. Variable is_i represents the capacity of installed solar PV (kWp), and variable ib_i represents the installed battery energy capacity of the battery (kWh). In the case of a passive consumer both is_i and

[11] No costs for operation or maintenance of DER technology is assumed.

[12] Please note that in the (extreme) case, when the total energy injected by a consumer is higher than the total energy withdrawn from the network, the network charges can be negative under volumetric network charges with net-metering.

ib_i are forced to zero. ICS and ICB are the investment costs per kWp solar capacity and kWh battery capacity respectively and AFS and ABS are the annuity factors for both technologies.

Consumers are subjected to a set of constraints, shown by Equations 6-15. Equation 6 represents the demand balance, meaning that demand should equal supply at all moments. $\mathrm{D_{t,i}}$ is the demand of consumer i at time step t.[13] The supply of electricity consists of the summation of electricity withdrawn from the grid, the electricity generated from PV and the energy discharged from the battery, minus the summation of the electricity injected into the grid and the electricity used to charge the battery. It is not possible to buy and sell electricity or discharge and charge the battery simultaneously. As such, $pw_{t,i}$ will be equal to zero if $pi_{t,i}$ is positive and vice-versa and the same holds for $pbout_{t,i}$ and $pbin_{t,i}$. $\mathrm{SY_{t,i}}$ stands for the time-varying solar yield in kW per KWp PV installed, which depends on the observed irradiation. PRS is the performance ratio of the solar panel. $pbout_{t,i}$ and $pbin_{t,i}$ are variables standing for the energy output and input respectively of the battery of consumer i at time step t.

$$\mathrm{D_{t,i}} = pw_{t,i} - pi_{t,i} + is_i * \mathrm{SY_{t,i}} + pbout_{t,i} - pbin_{t,i}\ \forall\ t \tag{6}$$

$$soc_{1,i} = pbin_{1,i} * \mathrm{EFC} * \mathrm{DT} - \frac{pbout_{1,i}}{\mathrm{EFD}} * \mathrm{DT} + \mathrm{SOC_0} \tag{7}$$

$$soc_{t,i} = pbin_{t,i} * \mathrm{EFC} * \mathrm{DT} - \frac{pbout_{t,i}}{\mathrm{EFD}} * \mathrm{DT} + soc_{t-1,i} * (1 - \mathrm{LR} * \mathrm{DT})\ \forall\ t \neq 1 \tag{8}$$

$$soc_{tmax,i} = \mathrm{SOC_0} \tag{9}$$

$$pw_{t,i} + pi_{t,i} \leq pmax_i\ \forall\ t \tag{10}$$

$$soc_{t,i} \leq ib_i\ \forall\ t \tag{11}$$

$$pbout_{t,i} \leq ib_i * \mathrm{BRD}\ \forall\ t \tag{12}$$

$$pbin_{t,i} \leq ib_i * \mathrm{BRC}\ \forall\ t \tag{13}$$

$$is_i \leq \mathrm{MS_i} \tag{14}$$

$$ib_i \leq \mathrm{MB_i} \tag{15}$$

$$pw_{t,i}, pi_{t,i}, soc_{t,i}, pbout_{t,i}, pbin_{t,i}, is_i, ib_i, pmax_i \geq 0 \tag{16}$$

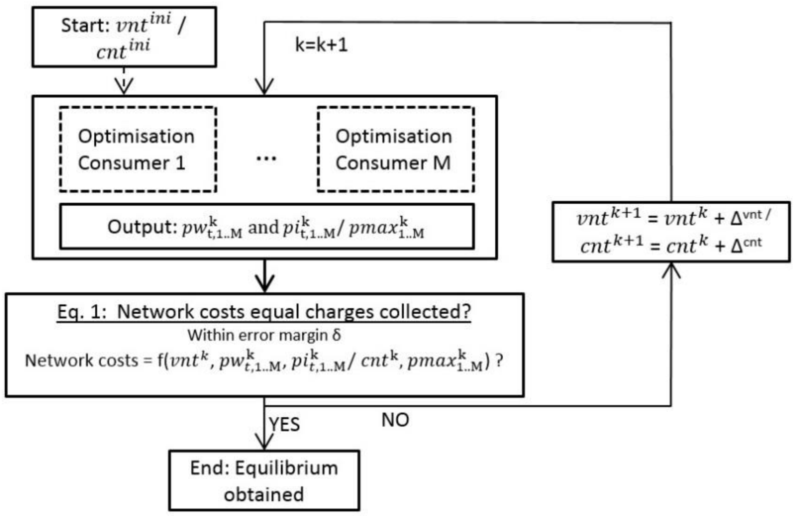
Equations 7-9 describe the battery balance. $soc_{t,i}$ stands for the state of charge of the battery of consumer i at time step t, $\mathrm{SOC_0}$ is the initial state of the battery, EFC and EFD are the efficiencies of charging and discharging respectively, LR is the leakage rate of the battery and DT is the length of time step as a fraction of an hour. By Equation 10 the peak withdrawal or injection $pmax_i$ over all time steps is determined. Equations 11-13 limit the energy stored, power discharged at a time step and power charged at a time step respectively. The parameters BRD and BRC define the maximum rate power discharged/charged over the energy capacity of the battery. The capacity of solar and batteries to be installed by a consumer i is capped by Equation 14-15. Equation 16 forces all lower level variables to be non-negative. The lower level formulation can be considered as a linearized version of a DER sizing problem with possibilities to invest in solar and batteries (See for example: Schittekatte et al. (2016)).

[13] In this paper the household power demand ($\mathrm{D_{t,i}}$) is an exogeneous parameter and instead the way the demand is met (grid, solar panel or battery) is an optimized decision for a reactive consumer. In future work also the household power demand could be modelled as a variable e.g. by introducing a price sensitivity of demand for electricity as in Van Den Bergh (2015).

3.2.3 The bi-level model: connecting upper and lower level

All individual consumers are connected to one another through the sunk grid cost recovery equality that is represented by Equation 1. An equilibrium is obtained if this equality holds and none of the consumers, for which the optimisation problems are described by Equations 2-16, has an incentive to adopt their electricity withdrawal and injection pattern from the grid by e.g. by installing more solar panels or using installed batteries in an alternate fashion. Different methods to solve the bi-level optimisation problem that is described by Equations 1-16 exist (See for example: Gabriel et al., 2012). In this paper, a solution is found through the application of a simulation approach. The coefficient of the network tariff (vnt or cnt) is iterated until an equilibrium is attained. The flow chart of the algorithm underlying the proposed simulation approach is presented in Figure 1.

Figure 1: Flow of the calculations to obtain the equilibrium



It is possible that multiple equilibria are found. However, by following this approach the algorithm terminates at the equilibrium for which the network tariff coefficient is the lowest among all possible equilibria. Among all possible equilibria, the increase in network charges for passive consumers, as well as the investment distortions of the reactive consumers, are most limited when the equilibrium with the lowest network charge coefficient is used.

4. Numerical example, result metrics and data

In this Section, firstly, the setup of the numerical example of the model is described. Secondly, the metrics to analyse the results are explained. Thirdly, the parameters that do not change over a different state of the world are presented and lastly, the parameter settings for the technology cost matrix are presented.

4.1 Setup

For simplicity, only two consumer types are modelled: passive and reactive consumers. Both consumer types have the same original electricity demand from the grid. The sole difference between the two consumer types is that a passive consumer does not have the option to invest in solar PV and batteries, and a reactive consumer can opt to invest in DER. Passive consumers are uninformed about the possibility to invest in DER. They either do not have the financial means, are strongly risk averse or simply do not have space. Reactive consumers are economically rational, i.e. minimise their costs to meet the electricity demand, and may invest in DER, if optimal. Note that the relative proportion of each consumer type is an important parameter for the sensitivity analysis of the results.

4.2 Proxies for efficiency and equity

Depending on the network tariff design in place, reactive consumers can offset their contribution to the sunk grid costs by investing in DER. In this case, the avoided contribution is reallocated to the passive consumers. However, the total costs to be recovered by the DSO remains the same, only the allocation of the contributions changes.

More precisely, if a reactive consumer invests in DER technology, its electricity bill reduces due to the avoided energy costs *and/or* network charges. The reactive consumer will only invest in DER if the difference between the reduction of the electricity bill and the DER investment cost is positive. The net reduction in the total electricity cost will be exactly this difference. The passive consumer does not invest in DER technology and will possibly see its electricity costs increase with the sunk costs shifted by the reactive consumer.

As an illustration, assume one reactive and one passive consumer. When no one invests in DER, the total electricity cost of all consumers is assumed the same as the consumers are identical. However, when investment in DER is allowed for a reactive consumer the respective change in electricity cost can be:

- Change for reactive consumer= – avoided energy cost by the reactive consumer – avoided network charges by the reactive consumer + investment cost in DER
- Change for passive consumer= + avoided network charges by the reactive consumer

The net aggregated decrease or increase in total electricity cost for the two consumers, referred to as the change in system costs, will be:

- Change system costs = – avoided energy cost by the reactive consumer + investment cost in DER

Price signals are distorted if the avoided energy cost by the reactive consumer is lower than the investment cost in DER. This would mean that the system cost increases. In simple terms, 'the losers' (the passive consumers) lose more than 'the winners' (reactive consumers) win. The system cost is calculated in this model as the summation of the objective function of both consumer types weighted with their respective proportion P_i[14]:

$$System\ cost = \sum_i P_i * (commodity\ costs_i + network\ charges_i + investment\ costs_i) \quad (17)$$

Fixed charges do not have a distortive effect in this model. Therefore, as a proxy for efficiency or 'non-distortionary', the system cost for a tariff structure is benchmarked with the system cost when fixed network charges are applied.

A proxy for the equity is introduced by looking at the allocation of the sunk costs to the two consumer's types. It is assumed that in the most equitable situation the sunk costs allocated to both consumer types are the same, as their original electricity demand before installation of DER from the grid is identical. When a reactive consumer invests in DER part of the sunk costs can be shifted to the passive consumer. The increase in network charges paid by the passive consumer compared to a situation where both consumer types pay the same fixed network charge is used as the proxy for equity.

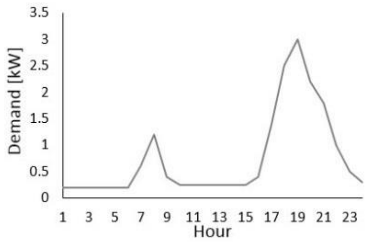
[14] The proportion of a consumer group is defined by the number of consumers represented by a consumer group i (N_i) divided by the total number of consumers connected to the distribution grid (N): $P_i = \frac{N_i}{N}$

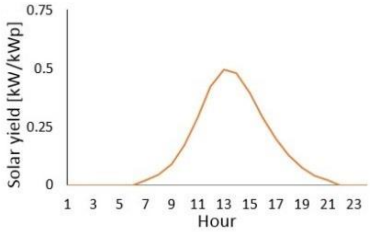
4.3 Data

In this stylised example the consumer demand and yield of a PV panel is represented using a time series of 24 hours with hourly time steps. (See Table III (middle and right)). The household demand for electricity shows a small peak in the morning and a stronger peak in the evening. The fulfilment of the demand is a hard constraint. The scaled annualised consumption of a consumer is 6.500 kWh with an annual peak of 3 kW. The relationship between the annual consumption and peak is based on Blank and Gegax (2014).[15] As a reference, in Europe average annual electricity consumption per household in 2015 ranged from 20.000 kWh (Sweden) to 1.400 kWh (Romania) (ACER, 2016). In the same year, the average electricity consumption per household in the USA was about 10.800 kWh (EIA, 2016a). Please note that this is a stylised example and the intention of this paper is not to analyse the impact of tariff design on consumers from a specific region. However, the adopted approach does not exclude such an analysis in the future.

Table III:
Technical DER Parameters (left), original demand profile (middle) and solar yield profile (right)

Parameters reactive consumer	Value
Lifetime PV	20 year
Lifetime battery	10 year
Discount factor PV and batteries	5 %
Maximum solar capacity installed	5 kWp
Maximum battery capacity installed	No limit
Efficiency charging & discharging	90 %
Leakage rate	2 %
Price received for electricity injected into the grid (% of wholesale price)	90 %





The yield per kWp PV installed scales up to 1160 kWh per year with the profile shown in Table III (right). This level is similar to the average yield in the territory of France (Šúri et al., 2007). As a reference, Formica and Pecht (2017) found a yield of 1300 kWh/kWp for a PV installation in Maryland, USA and Mason (2016) finds that in the UK the average yield equals 960 kWh/kWp. Remaining technical DER and other relevant parameters are shown in Table III (right). Technical DER data is in line with Schittekatte et al. (2016), other parameters are considered as reasonable assumptions. Finally, the price received for electricity injected into the central grid (also called the 'feed-in tariff') is set to 90 % of the assumed cost for energy from the grid, excluding grid or any other charges. The energy cost relates to the electricity wholesale price and includes a retailer margin.

In Table IV the composition of the consumer bill is presented. This is the consumer bill in the default setting, i.e. a situation without investment in DER technology by any consumer. If reactive consumers decide to invest in DER, the relative proportion and absolute values of the bill components will change for both the reactive and the passive consumer. The consumer bill is based on information from the market monitoring report for electricity and gas retail markets by ACER (2016). There, the breakdown of the different components of the electricity bill for an average consumer in the EU for the year 2015 is presented. The energy component of electricity prices in the EU in 2015 is estimated to be 37%. In nominal terms, this means a cost of 0.074 €/kWh. Further, 26 % of the bill consisted of network charges and 13 % are RES and other charges. Finally, an important chunk (25%) of the bill consists of taxes. A value-added tax (VAT), averaging 15%, must be paid and additional (ecological) taxes, averaging 10 %, are raised on the use of power in some countries.

[15] In that paper a regression analysis using a small data sample of households in Alaska is done. The authors find a that an increase in monthly energy use by 1,000 kWh would increase maximum monthly demand by 5.5 kW. For the sake of simplicity these findings are extrapolated to a yearly basis.

The taxes are integrated into the remaining three components: energy costs, network charges and other charges. The default electricity bill of the consumer consists of 45% energy costs, 35% network charges and 20% other charges. The energy price is set at 0.08 €/kWh consumed.[16] Other charges are recovered through a fixed fee and as such do not interfere with the analysis. However, this is not always the case, as described in Frondel et al. (2015). The question of how to collect such charges, or even whether they belong in the electricity bill at all, is out of the scope of this work. The network charges, the focus of this work, are recovered through the different network tariff designs.

Table IV:
Consumer bill for in the default case, when no investment in DER by any consumer is made

Default consumer bill	Proportion of the bill	Cost per year	Recovery
Energy costs	45 %	520 €/year	0.08 €/kWh
Network charges	**35 %**	**404 €/year**	**Through the different network tariffs**
Other charges	20 %	231 €/year	Fixed fee (does not interfere)
Total electricity cost	Average of 0.18 € per kWh delivered	1155 €/year	

The total annual electricity cost, including also the network and other charges, equals 1155 €/year or 0.18 €/kWh delivered. This total cost is near to the average electricity cost for EU households in 2015 that was estimated around 0.21€/kWh (Eurostat, 2016). In the USA the average electricity cost in 2015 for residential use was lower, namely around 0.125€/kWh (EIA, 2016b).

Also a typical consumer bill varies widely over time and, additionally, is country context dependent. The energy cost component in the EU has fallen since 2012, both in nominal terms, from 0.08 to 0.074 €/kWh, and as a percentage of the final consumer bill (ACER, 2016). The proportion of the energy component of a typical residential electricity bill ranges from 78 % in Malta to solely 14-13 % in Norway and respectively Denmark. Not only the energy component but also the proportion of grid costs in the final bill was found to vary significantly. According to a recent European Commission (2015) report, the share of distribution cost paid by residential users in the EU ranges from 33% to 69% in the final consumer bill. High network charges are not always related to high costs of physical grids, but might be 'artificially' inflated. In some countries, costs have been added to the DSO's costs that are not directly tied to providing an incremental kWh of electricity, e.g. costs for energy efficiency programs and subsidies for installing distributed generation (Borenstein, 2016; European Commission, 2015; Huijben et al., 2016). In future work the sensitivity of the results to the country context will be investigated.

4.4 The technology cost matrix

The values of the key parameter for the different states of the technology cost matrix are displayed in Table V. The numbers for the investment cost in residential PV agree with low and high estimates of prices found in RMI (2015). As the cost of a kWh generated by 1 kWp of PV installed is a function of several parameters, the levelised cost of energy (LCOE) is calculated as an additional reference value.[17] The LCOE for the high and low PV cost scenario is equal to 0.18 €/kWh and 0.09 €/kWh respectively and these LCOE estimates are in line with the ranges presented in Lazard (2016a). The same sources (Lazard, 2016b; RMI, 2015) are used to obtain the high and low investment cost scenario for lithium-ion battery packs. It is further assumed that the minimum time needed to fully (dis)charged the energy capacity of the battery is one hour. No investment subsidies for PV or batteries are introduced.

[16] In this work the energy cost is modelled exogenously. In cases with high PV adoption this might be a simplification as a higher penetration of PV can have a depressing effect on wholesale prices (see e.g. Darghouth et al. (2016))

[17] In the model applied the LCOE of PV is a function of the investment cost of the PV panel, lifetime, discount factor, the PV system performance ratio and the solar irradiation profile.

Table V: Main parameter settings of the technology cost matrix

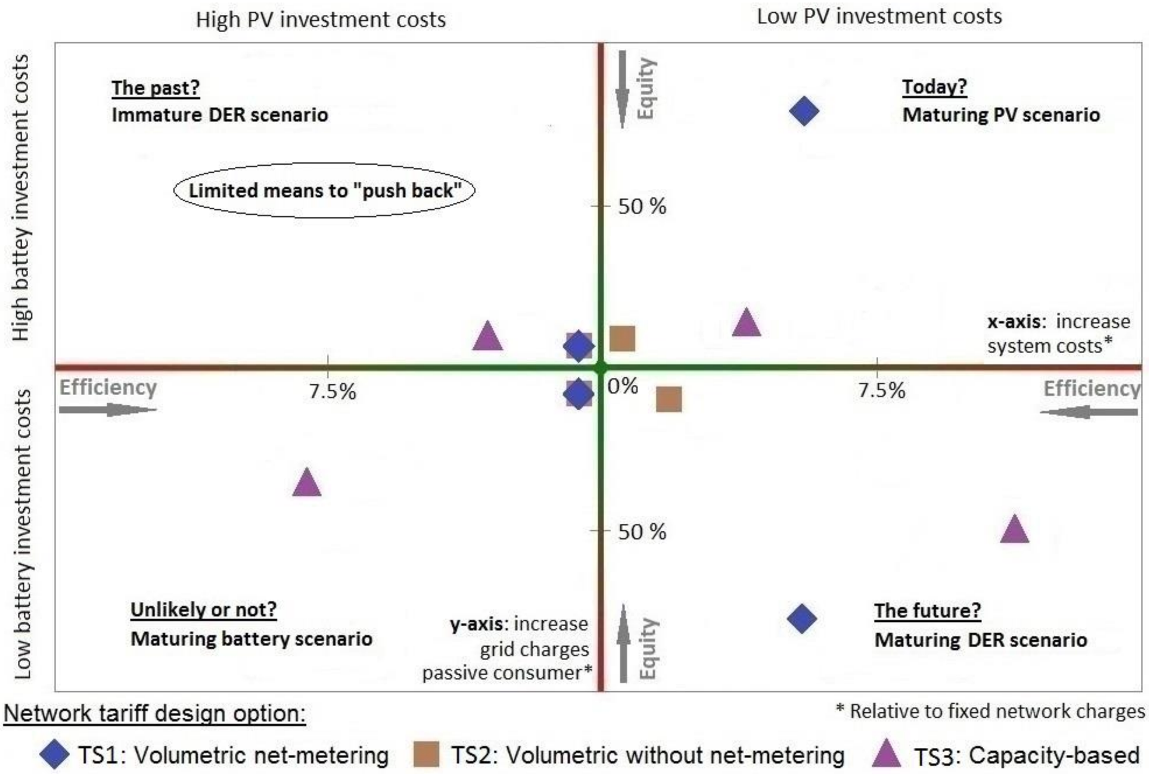
	High technology costs	Low technology costs
Investment cost PV	2600 €/kWp (LCOE: 0.18 €/kWh)	1300 €/kWp (LCOE: 0.09 €/kWh)
Investment cost batteries	600 €/kWh (full (dis)charge in 1 hour)	200 €/kWh (full (dis)charge in 1 hour)

Please note that e.g. high investment costs for PV panels could also be interpreted as installing those panels in parts of the world with less solar irradiance and vice-versa. It is harder to come up with a similar interpretation for the battery investment costs. However, the battery is used to shift power demand from the grid in time, a function which could also be provided by the demand response.[18]

5. Results and discussion

The results obtained for the different tariff structures are displayed in Figure 2. Figure 2 is split up into four quadrants, representing the four states of the world. A proportion of reactive consumers, able to invest in PV and batteries when economically rational is assumed to be 50 %. The proportion of reactive consumers is further discussed when the results are described. For each state of the world, the performance is shown of the three tariff structures for the efficiency proxy, on the vertical axis, and for the equity proxy, on the horizontal axis. The closer the result of a tariff structure is to the origin along one axis, the better its performance for the metric displayed on the other axis.

Figure 2: The results for the four states of the world with 50 % reactive consumers connected to the grid. Results for the efficiency (horizontal) and equity (vertical) proxy are shown.



[18] Demand response is not modelled. The cost of demand response would be dependent on the value a consumer attributes to the need of power at a particular time. Such an analysis is out of the scope of this work.

The results for the different tariff structures can be compared to each other in a specific state of the world. Also, the relative performance of a certain tariff structures in different state of the worlds can be assessed. This work does not attempt to discuss the trade-off between efficiency and equity. Only if a tariff structure dominates another tariff structure for both the efficiency and the equity metric, it can be said that one outperforms the other. In the next Subsections, the results are described per state of the world. The dynamics behind the results are described in detail for the 'Maturing DER scenario'. This Section ends with a short discussion on the implementation of capacity-based charges.

5.1 Immature DER scenario, the past?

Two observations are made in this state of the world. Firstly, the results show that applying volumetric network charges with net-metering, the network tariff design historically in place, does not create efficiency or equity issues for the recovery of the sunk costs. The same result is found for volumetric network charges without net-metering. This can be explained by the fact that consumers do not have means to react to prices as PV is simply too expensive to invest in. A second observation is that with capacity-based network charges some inefficiencies, but very limited equity issues arise. This can be explained by investment in small but expensive batteries by the reactive consumers to shave their peak consumption. As the batteries are small, only a small proportion of the sunk costs are shifted to the passive consumers.

5.2 Maturing battery and expensive PV scenario, unlikely scenario or not?

A state of the world with high PV investment costs and low battery costs is rather unlikely. However, this technology cost scenario could be the thought of as the future for places where electricity generated by PV is too expensive due to low levels of solar irradiation combined with few government subsidies. Alternatively, an unexpected battery R&D breakthrough could bring forward this scenario. Two observations from this state of the world are described below.

Firstly, results for volumetric charges with and without net-metering do not change. Net-metering does not incentives investments in batteries for reactive consumers.[19] Therefore, the investment cost of batteries does not have any effect on the results for this tariff structure. Under volumetric network charges without net-metering there is an incentive to install batteries. A consumer must pay network charges both for withdrawal and injecting of energy into the grid. This means that a consumer is incentivised to self-consume his electricity generated on-site by PV. Consequently, under this tariff structure, when a consumer installs PV it can make sense to install additional batteries to limit the amount of electricity injected into the network when PV generation is high and demand low. The energy collected in the batteries can then be used to serve the electricity demand when the situation is reversed. As such, the exchange of electricity with the grid, and thus the network charges paid, will be limited. However, in this state of the world PV is expensive and therefore no PV is installed by the reactive consumer. As no PV is installed, also no batteries will be installed and therefore the results do not differ from those of the previous state of the world.

Secondly, increased inefficiencies and a more severe equity issue resulted with capacity-based charges when compared with the previously described state of the world. Reactive consumers install batteries with a higher capacity as these are rather inexpensive. Since batteries are cheap, the increase in system costs, the proxy for efficiency, is dampened. An equity issue results as the reactive consumers can shave their peak demand more significantly with the higher battery capacity installed per reactive consumer.

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[19] When energy prices or network charges would be time-varying also batteries adoption could result with volumetric charges without net-metering.

5.3 Maturing PV scenario, today?

Three observations can be made for this state of the world. Firstly, volumetric network charges with net-metering create severe equity issues and inefficiencies. Since reactive consumers install the maximum amount of PV of which the excess generation is fed into the grid, the netted-out electricity consumption of the reactive consumers from the grid is significantly lowered. Consequently, the network charge coefficient in €/kWh must increase to allow for cost recovery. This means that the network charges paid by the passive consumers increase strongly. Additionally, investment distortions are created with this network tariff structure. More precisely, the LCOE of PV for this scenario is slightly higher than the energy cost of electricity and the price received for injecting electricity into the grid. In the case a network tariff does not interfere with the volumetric (€/kWh) or capacity (€/kW) price signal, no investment in PV is expected from the rational cost minimising consumer. With volumetric network charges with net-metering in place, investing in PV becomes a lot more attractive as not only energy costs can be avoided but also network charges. These results confirm the findings of Eid et al. (2014). They concluded that net-metering creates significant equity issues for non-PV owners and acts an implicit subsidy for the adoption of PV.

A second observation is that the result for volumetric network charges without net-metering almost does not change when compared to the previously discussed scenarios. PV is inexpensive, and if reactive consumers would install PV they would avoid paying network charges for withdrawing electricity from the grid. However, the electricity demand is not always at the same level as the PV production and vice-versa. Therefore, the business case for a reactive consumer to install a large capacity of PV is not attractive, and only a very limited capacity of PV is installed. Batteries can increase the amount of electricity produced on-site that could be used for self-consumption. However, in this state of the world these are expensive and no batteries are installed.

The last observation for is that the performance of capacity-based charges is impacted by a change in the PV investment cost while keeping the battery investment cost constant. This effect is even stronger visible when comparing the two states of the world with low battery costs and different PV investment costs. Lowered PV costs incentivise investment in PV under this tariff structure and consequently also investment in batteries becomes more attractive. This is rather surprising as can be seen from the demand and solar yield profile on Table III (middle and right) that the solar profile and peak demand are highly uncorrelated. This dynamic shows that there is value in considering both investment possibilities in PV and batteries simultaneously when studying capacity-based charges in a setting with reactive consumers. Equity issues are limited as the capacity of batteries installed is small and the correlation of the solar yield profile and the peak demand of the consumer is low.

5.4 Maturing DER scenario, the future?

Three highlights are described for this state of the world. To begin with, Figure 2 shows that the results for volumetric charges with net-metering in this state of the world do not change when compared to the previously described state. This is expected as the only parameter changing between those two states is the battery investment cost, and with net-metering and no time-varying process in place, a reactive consumer has no reason to install batteries.

Secondly, the results for volumetric charges without net-metering change slightly. In this state of the world, the reactive consumers invest in PV and batteries. Inexpensive batteries increase the amount of electricity produced by PV that can be used for self-consumption. As such, the total amount of network charges paid by the reactive consumer decreases. However, the amount of avoided network charges is limited, and the installed capacities of both PV and batteries remain small. Volumetric network charges without net-metering are rather robust against investment distortions and equity issues, even in this state of the world with low DER costs and 50 % of reactive consumers connected to the grid.

Thirdly, the results for capacity worsen significantly, both in terms of efficiency and equity, when comparing to the other state of the worlds. This result will be elaborated on more deeply to demonstrate why this is happening. In Figure 3 the results for efficiency and equity proxy with sensitivity for the proportion of reactive consumers connected to the grid is shown. For all three tariff structures the magnitude of the inefficiencies and equity issues increases with an increased share of reactive consumers. This is relatively straightforward because there are simply more reactive consumers with distorted investment incentives who are trying to shift the grid costs to a smaller share of passive consumers. This dynamic could be a labelled as an effect of big numbers and is also captured by more static quantitative models as Hledik and Greenstein (2016)[20] and Simshauser (2016). However, a second effect makes the increase in inefficiencies and equity issues very non-linear and unpredictable. The origin of this effect is non-cooperative behaviour between consumers and the result is that *the capacity of DER technology installed per individual reactive consumer can increase with an increased share of reactive consumers connected to the grid*. In this scenario and under capacity-based charges, the optimal battery capacity installed per reactive consumer increased from 2.5 kWh with nearly no reactive consumers, to 5.5 kWh with 50 % reactive consumers connected to the grid.

Figure 3: Results for the efficiency proxy (left) and the equity proxy (right) with sensitivity analysis for the proportion of reactive consumers.

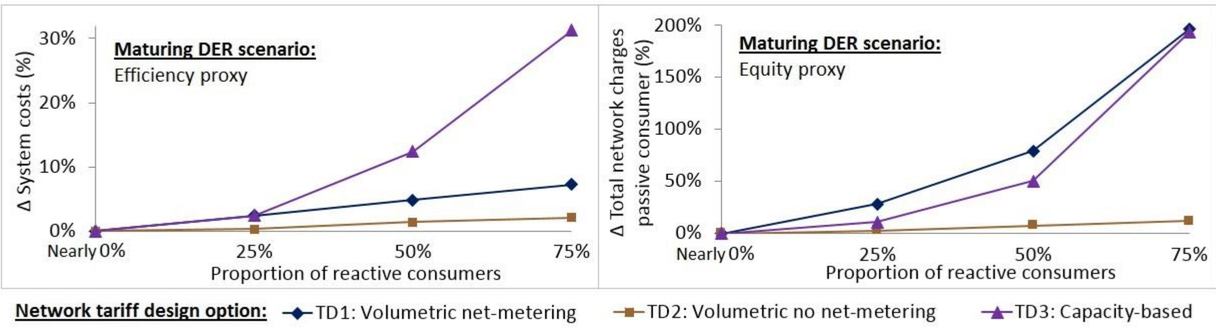
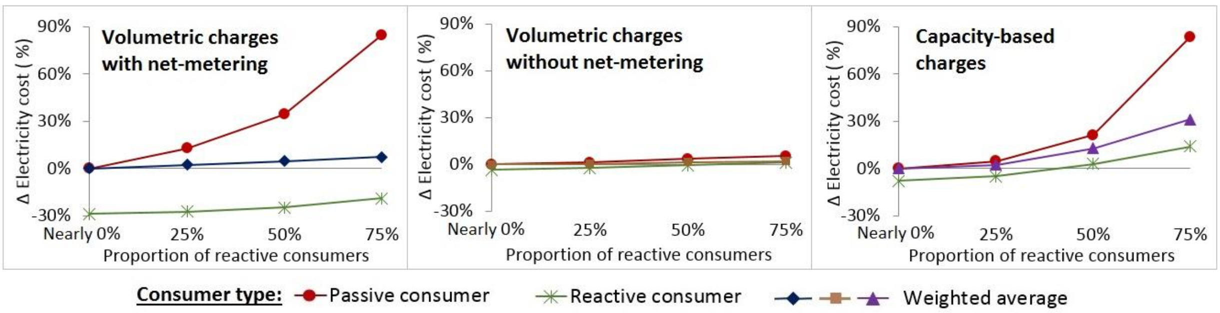


Figure 4 helps to further explain the adverse effect of non-cooperative behaviour on the efficiency and equity proxy. In Figure 4 the annual electricity cost of the two consumer types, relative to the baseline case with non-distortive fixed network charges, is shown. Additionally, system cost, calculated as the weighted average electricity cost and used as a proxy for efficiency, is shown.

Figure 4: Difference in annual electricity cost per consumer type for the three network tariff structures compared to the application of non-distortive fixed network tariffs. Additionally, the weighted average electricity cost (or system cost), serving as the proxy for efficiency, is shown.



20 In their paper the authors develop a preliminary understanding of the relationship between capacity-based charges and storage. A home battery with a certain size is assumed and the cost of the battery for the consumer is not accounted for. The optimal sizing of the battery and the interaction between the sizing and the proportion of reactive consumers connected to the grid is not attempted, however, mentioned to be a valuable area of research.

When the proportion of reactive consumers connected to the grid is very limited a reactive consumer can lower his electricity bill under all tariff structures. Reactive consumers can profit the most under volumetric charges without net-metering by installing the maximum capacity of PV. The decrease in the electricity bill of the reactive consumer, compared to the baseline case, is the results of the low DER investment costs. As the proportion of reactive consumers is limited, the total grid costs shifted to the numerous passive consumers and the rate increase of the network charge needed to ensure cost recovery for the DSO is minimal. Therefore, the increase in the electricity cost for the passive consumer is limited. It can also be observed that the electricity cost of an individual reactive consumer increases with an increased share of reactive consumers connected. It is surprising to see that under volumetric charges without net-metering and capacity-based charges the electricity cost of the reactive consumer surpasses the electricity cost for that same consumer in a situation where all consumers are passive and do not invest in DER at all. On first sight, this outcome might seem counter-intuitive: *Why would a consumer invest in DER when everybody, including himself, is better off when nobody invests in DER?*

This dynamic can be explained by the fact that cost-minimizing reactive consumers take uncoordinated investment decisions by following their own self-interest. The results of the model can be interpreted as a Nash equilibrium, defined as a solution of a non-cooperative game involving two or more players in which each player is assumed to know the equilibrium strategies of the other players, and no player has anything to gain by changing only his or her own strategy (Nash, 1951; Osborne and Rubinstein, 1994). In this context, a Nash equilibrium implies that no consumer has anything to gain by changing only his own operational and investment decisions. Concretely, for a certain share of reactive consumers, an individual consumer would not install more DER as in this case the additional investment does not justify the decrease in network charges and/or energy costs. On the other hand, for the same share of reactive consumers, an individual consumer would also not install less DER as that would mean his total electricity cost goes up as he would have to pay more network charges and/or energy costs. In a setting where all reactive consumers would jointly make an investment decision, it would be decided to install a lower amount of DER than in the case they make an individual decision. This would be an optimal solution as the overall efficiency would increase. With the game-theoretical model applied in this work, it is possible to capture and quantify the adverse effect of non-cooperative behaviour between reactive consumers.

Uncoordinated decision making does not only have an adverse effect on the aggregated electricity cost of all consumers but also on the electricity cost of the group of reactive consumers. In other words, reactive consumers are cannibalising their own 'profit' by competing against each other. *This adverse effect, which leads to a race (to the bottom) of DER adoption, can be minimised or enabled by adequate network tariff design.* For this scenario, the results show that capacity-based charges are more prone to enable this loop, which creates severe efficiency and equity issues. It can also be seen that this effect kicks in for volumetric charges without net-metering, however, less intense and delayed when compared to capacity based charges.[21] The same effect does not affect volumetric charges with net-metering for this scenario simply because the reactive consumer already installed the maximum amount of PV capacity (5 kWp) when the proportion of reactive consumers was negligible.[22]

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[21] Additional sensitivity runs were conducted and strong adverse effects of non-cooperative behavior were found for volumetric charges without net-metering in a scenario with very high grid costs (€ 1000 per consumer) and high energy cost (0.15 €/kWh).

[22] For more details on the interaction between net-metering and PV adoption see e.g. Cai et al. (2013) and Darghouth et al. (2016). In those work models are used to simulate PV adoption and rate adjustments over 20 and respectively 35 years.

5.5 Implementation matters: on the limitations of capacity-based charges to recover sunk costs

With capacity-based charges in place, investment in batteries and PV was strongly (over)incentivised in some scenarios. This network tariff structure was found to be prone to adverse effects of non-cooperative behaviour, leading to an increased capacity of DER installed per individual consumer when the share of total reactive consumers increases. The reacting consumers are competing and try to push the sunk cost burden to the non-reacting consumers, but also to one another. Hledik (2014) and Hledik and Greenstein (2016) point out that there is no single type of capacity-based network charges, but that many variants exist. Depending on the implementation of the capacity-based charge results could resemble or depart from the outcomes presented.

In this work a capacity-based network charge measuring the observed peak demand during one hour was used. A 24-hour deterministic profile including the demand peak was used in this work and results were annualised. By doing so it is assumed that the battery can perfectly anticipate when the peak demand takes place. Two design parameters of the capacity-based network charge can determine the level of (in)accuracy of the assumption of perfect foresight of the peak demand. Firstly, ‘the ratchet or billing cycle’ of a capacity-based charge, i.e. is the peak demand determined on a daily, monthly, seasonally or annual basis to calculate the network charges. Logically, the longer the period over which the peak demand is observed, the more inaccurate perfect foresight of the peak demand would be. Secondly, the duration over which the peak demand is measured, i.e. instantaneously, averaged over fifteen minutes, averaged over one hour, or averaged over several hours, etc. The shorter the period over which the peak measurement is averaged, the more inaccurate a perfect forecast of the peak demand is. Shorter averaging period increases uncertainty around the forecast. Thus ‘badly designed’ capacity charges for sunk cost recovery, e.g. based on the hourly peak demand over a monthly period, could resemble the results of this analysis. While capacity based charges based on the peak demand during 15-minutes with a seasonal or annual ratchet would perform better than the results shown in this analysis. However, if the investment cost of batteries is low enough or grid costs to be recovered through the tariff are high, similar dynamics would result, independent of the design of the capacity-based charge.

6. Conclusion

Low-voltage consumers cannot be considered as passive anymore after two technology breakthroughs: (1) PV enables domestic and commercial consumers to self-produce energy; (2) Batteries enable self-producers to choose both their grid energy and capacity parameters. The availability and costs of these new technologies strategically interact with tariffs to recover grid costs as active consumers will react with their profit-maximising actions to any network tariff charged to them.

Three different distribution network tariff structures were evaluated in four states of the world for user’s access to these two technologies with the aid of a game-theoretical optimisation model. This approach allowed to capture the reaction of consumers to different tariff design by the adoption of DER technologies. The three tariff structures that were assessed are: energy volumetric charges with net-metering, energy volumetric charges for both injection and withdrawal and capacity-based charges. Each tariff structure was evaluated with a proxy for efficiency and equity. A central assumption was that grid costs to be recovered by the DSO were sunk, i.e. the adoption of DER technology by consumers does not influence the total costs to be recovered.

The results confirm that DER adoption by low voltage consumers is sensitive to network tariff design. No 100 % “future-proof” network tariff design was identified. In a world with an increasing share of consumers connected to low voltage distribution networks reacting to price signals, simple netted out volumetric network charges to recover grid costs cannot be considered as the adequate network tariff design. Net-metering creates significant equity issues for non-PV owners and is an implicit subsidy for the adoption of PV.

Depending on the state of the world and its implementation, also capacity-based charges can severely distort the investment decisions of consumers. These results nuance the findings of the pro-capacity-based camp, e.g. Hledik and Greenstein (2016) and Simshauser (2016). It was shown that capacity-based network charges are prone to the adverse effects of non-cooperative behaviour between consumers. Reactive consumers make uncoordinated investment decisions to push sunk grid costs to one another which can lead to overinvestment in DER and subsequently equity issues. This effect was captured by modelling the grid cost recovery problem as a non-cooperative game between consumers.

The observed dynamics confirm the suggestion made by Simshauser (2016), namely that if the capacity-based charge overstates the value of peak load it may pull-forward battery storage and create a new dimension to the sunk cost recovery problem. It was found that simply abolishing net-metering and applying so-called 'bi-directional' volumetric charges ; an option also brought forward by Eid et al. (2014), can outperform capacity-based charges to recover sunk costs in a future scenario low technology costs and a high proportion of reactive consumers. This tariff design is found to be more robust against the adverse effects of non-cooperative behaviour. Investment decisions are less distorted and the sunk costs are shared more equitable among different consumer types.

By considering grid costs to be sunk, we focused on the limitations of capacity-based charges. Admittedly, this assumption presents a simplification in countries where the distribution network is in full expansion and therefore it will be challenged in future work. By doing so, the total costs to be recovered by the DSO will become a function of network usage. In that setting, with low sunk costs and high future demand-driven investment, intelligently designed capacity-based charges could be of use. Lowered future grid costs due to intelligent grid charges could dampen the effects of non-cooperative behaviour. Another potential future research line would be to investigate the risk of grid defection when fixed charges would be increased strongly. Also, the effect of time-varying price signals, which would add value to the battery, would provide interesting insights.

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Appendix: Overview of the used sets, parameters and variables

Sets
i : 1,..,N: Consumers
t: 1,..,tmax: Time steps with a certain granularity

Parameters
α: Proportion of grid investment to be recovered by volumetric charges [0-1]
β: Proportion of grid investment to be recovered by capacity charges [0-1]
δ: Allowed band wherein the grid costs to be recovered by volumetric and/or capacity charges can differ from the grid charges collected, as a percentage of total network costs [%]
WDT: Scaling factor to annualize, dependent on length of the used time series and time step [-]
DT: time step, as a fraction of 60 minutes [-]
N_i : number of consumers represented by consumer (type) i
N : total number of consumers connected to the distribution grid
$\mathrm{D}_{t,i}$: Original demand at time step t of agent i [kW]
MS_i : Maximum solar capacity that can be installed by agent i [kWp]
MB_i : Maximum battery capacity that can be installed by agent i [kWh]
$\mathrm{SY}_{t,i}$: Yield of the PV panel at time step t of agent i [kW/kWp]
EBP_t: Energy price to be paid by agent for buying from the grid [€/kWh]
ESP_t: Energy price received by agent for buying from the grid (Feed-in tariff) [€/kWh]
ICS: Investment cost for solar [€/kWp]
ICB: Investment cost for batteries [€/kWh]
AFS: Annuity factor solar [-]
AFB: Annuity factor batteries [-]
BDR: Ratio of max power output of the battery over the installed energy capacity [-]
BCR: Ratio of max power output of the battery over the installed energy capacity [-]
EFD: efficiency of discharging the battery [%]
EFC: efficiency of charging the battery [%]
LR: leakage rate of the battery [%]
SOC_0: original (and final) state of charge of the battery [kWh]

Variables
<u>UL decision variable</u>
vnt : Volumetric network tariff [€/kWh]
cnt: Power network charge [€/$\mathrm{kW}_{\mathrm{yearly\_peak}}$]
<u>LL decision variable</u>
$pw_{t,i}$: Power bought at time step t by agent i [kW]
$pi_{t,i}$: Power sold at time step t by agent i [kW]
$pmax_i$: Yearly peak demand of agent i [kW]
$soc_{t,i}$: State of charge of the battery of agent i at step t [kWh]
$pbout_{t,i}$: Discharge of the battery of agent i at step t [kW]
$pbin_{t,i}$: Power input into the battery of agent i at step t [kW]
is_i: Installed capacity of solar by agent i [kWp]
ib_i: Installed capacity of the battery by agent i [kWh]

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