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EUI Working Paper **RSCAS** 2019/02

ISSN 1028-3625

Printed in Italy, January 2019
European University Institute
Badia Fiesolana
I – 50014 San Domenico di Fiesole (FI)
Italy
www.eui.eu/RSCAS/Publications/
www.eui.eu
cadmus.eui.eu

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Abstract

In many countries, distribution grid tariffs are being reformed to adapt to the new realities of an electricity system with distributed energy resources. In Europe, legislative proposals have been made to harmonize these reforms across country borders. Many stakeholders have argued that distribution tariffs are a local affair, while the EU institutions argued that there can be spillovers to other countries, which could justify a more harmonized approach. In this paper, we quantify these spillovers with a simplifed numerical example to give an order of magnitude. We look at different scenarios, and find that the spillovers can be both negative and positive. We also illustrate that the relative size of the countries is an important driver for the signifcance of the effects. To be able to quantify these effects, we developed a long-run market equilibrium model that captures the wholesale market effects of distribution grid tariffs. The problem is formulated as a non-cooperative game involving consumers, generating companies and distribution system operators in a stylized electricity market.

Keywords

Distribution grid tariff design, Distributed energy resources, Non-cooperative game, Mixed complementarity problem, Spillovers

Nomenclature

Sets

$\mathcal{A}$	Set of agents in the non-cooperative game, indexed by a.
$\mathcal{I}$	Set of countries, indexed by i.
$\mathcal{J}$	Set of residential consumer segments, indexed by j.
$\mathcal{K}$	Set of conventional generator technologies, indexed by k.
$\mathcal{T}$	Set of time steps, indexed by t.

Parameters

$\overline{\mathrm{cap}}^{\mathrm{pv}}_{i,j}$	Maximum PV capacity that can be installed by consumer $C_{i,j}$, MW.
$\overline{\mathrm{cap}}^{\mathrm{s}}_{i,j}$	Maximum storage capacity that can be installed by consumer $C_{i,j}$, MWh.
CR	C-rate of a storage system, MW/MWh.
CT	Cost of transmission, €/MWh.
$\mathrm{DC}^{\mathrm{tot}}_{i}$	Total annual (sunk) costs of the distribution system operator in country i, €.
$\mathrm{D}^{\mathrm{nres}}_{t,i}$	Non-residential electricity demand at time step t, MWh.
$\mathrm{D}_{t,i,j}$	Electricity demand of consumer $C_{i,j}$ at time step t, MWh.
EC	Charging efficiency of a storage system, -.
ED	Discharging efficiency of a storage system, -.
$\mathrm{IC}^{\mathrm{conv}}_{k}$	Annualized investment cost of conventional generating technology k, €/MW.
$\mathrm{IC}^{\mathrm{pv}}$	Annualized investment cost of PV, €/MW.
IC^{s}	Annualized investment cost of storage, €/MWh.
IC^{w}	Annualized investment cost of a wind turbine, €/MW.
$\mathrm{LF}^{\mathrm{w}}_{t,i}$	Load factor of wind turbines at time step t, -.
$\mathrm{LF}^{\mathrm{pv}}_{t,i}$	Load factor of PV at time step t, -.

$\mathrm{N}_{i,j}$ Number of residential consumers belonging to segment j in country i, -.

$\mathrm{u}_i^{\mathrm{fix}}$ Binary parameter determining if fixed tariff structure is imposed in country i, -.

$\mathrm{u}_i^{\mathrm{nm}}$ Binary parameter determining if volumetric tariff structure with net-metering is imposed in country i, -.

$\mathrm{u}_i^{\mathrm{pd}}$ Binary parameter determining if peakd demand-based tariff structure is imposed in country i, -.

VC_k Variable cost of generating technology k, €/MWh.

Primal Variables

$\lambda_{t,i}$ Electricity market clearing price in country i at time step t, €/MWh.

$a_{t,i}$ Electricity imported by country i at time step t, MWh.

$cap_{i,k}^{\mathrm{conv}}$ Installed capacity of conventional generator technology k in country i, MW.

$cap_{i,j}^{\mathrm{pv}}$ PV capacity installed by consumer $C_{i,j}$, MW.

$cap_{i,j}^{\mathrm{s}}$ Storage capacity installed by consumer $C_{i,j}$, MWh.

cap_i^{w} Installed capacity of wind turbines in country i, MW.

$ch_{t,i,j}$ Energy charged to storage system of consumer $C_{i,j}$ at time step t, MWh.

$dc_{t,i,j}$ Energy discharged from storage system of consumer $C_{i,j}$ at time step t, MWh.

$e_{t,i,j}$ Energy content of storage system of consumer $C_{i,j}$ at time step t, MWh.

f_t Electricity transported over transmission line at time step t, MWh.

$g_{t,i,k}^{\mathrm{conv}}$ Electricity generated by conventional generator technology k in country i at time step t, MWh.

$g_{t,i,j}^{\mathrm{pv}}$ Electricity generated by PV system of consumer $C_{i,j}$ at time step t, MWh.

$g_{t,i}^{\mathrm{w}}$ Electricity generated by wind turbines in country i at time step t, MWh.

tar_i^{fix} Distribution tariff under the fixed tariff structure in country i, €/year.

tar_i^{nm} Distribution tariff under the volumetric net-metering tariff structure in country i, €/MWh.

tar_i^{pd} Distribution tariff under the peakd demand-based tariff structure in country i, €/MW.

$w_{i,j}^{\text{net}}$ Net withdrawal of consumer $C_{i,j}$ over all time steps $t \in \mathcal{T}$, MWh.

$w_{i,j}^{\text{peak}}$ Peak withdrawal from or injection into the grid of consumer $C_{i,j}$ at one time step t, MW.

$w_{t,i,j}$ Electricity withdrawn from the grid by consumer $C_{i,j}$ at time step t, MWh.

1. Introduction

Traditional volumetric distribution grid tariffs, especially in combination with net-metering policies, have caused welfare transfers between consumers and cost recovery problems for distribution system operators (DSOs) (Eid et al., 2014). To address these challenges, researchers, regulators and DSOs have proposed other, more cost-reflective distribution tariff designs with different combinations and implementations of fixed, volumetric and peak demand-based charges (Abdelmotteleb et al., 2018; Hledik and Greenstein, 2016; Borenstein, 2016). At the same time, the European Commission proposes to harmonize transmission and distribution grid tariff designs on the European level in its Clean Energy Package (European Commission, 2016). These network tariffs are currently set autonomously by the national regulatory authorities (NRAs) across Europe. The European Commission argues that unharmonized distribution tariff design may distort the level playing field on the internal electricity market in Europe as production is increasingly decentralized. Indeed, distribution grid tariffs may be seen as a form of state aid for distributed energy resources (DERs). On top of this, there may be spillover effects of distribution tariffs in neighboring countries, i.e., the welfare of consumers and the business case for DERs in a country may be impacted by the distribution grid tariff design imposed in a neighboring country. Many stakeholders have, however, argued that distribution grid tariff design should remain a national prerogative (CEER, 2017; CEDEC, 2017; Eurelectric, 2017). Eurelectric (2017), for instance, agrees that transmission tariffs should be harmonized to safeguard a level playing field, but argues that this is not necessary for distribution tariffs as they are "closely linked to local specificities".

The interaction between distribution tariff structures and DER investment has been studied extensively. Many researchers focus on volumetric net-metering tariffs that incentivize investments in photovoltaics (PV) (Simshauser, 2016; Eid et al., 2014; Laws et al., 2017; Brown and Sappington, 2017). Simshauser (2016) finds that net-metering policies in Southeast Queensland in Australia have led to significant welfare transfers from non-solar to solar households, thus forming an "implicit subsidy" for PV. He argues for a tariff with a large peak demand-based component to replace the current tariffs. Schittekatte et al. (2018), however, show how peak demand-based tariffs incentivize inefficient storage investment if the DSO's costs are sunk. All aforementioned research does not regard the possible impact of these distribution tariffs on other countries. To fill this gap, this work focuses on the spillover effects of distribution grid tariffs in neighboring, interconnected countries through coupled wholesale markets. To this end, we model the interaction between consumers, generating companies and distribution system operators in a simplified wholesale electricity market, spanning two interconnected countries, as a non-cooperative game. For each country, we consider active consumers (who can invest in PV and storage) and passive consumers (who cannot invest). The proposed model, formulated as a mixed complementarity problem (MCP), considers the investments in large-scale generation capacity by generating companies and the DER investments by active consumers to arrive at a competitive long-run equilibrium of the electricity market. The NRAs in each country impose one of three distinct distribution grid tariff designs, i.e., a tariff consisting of a fixed charge (FIX), a tariff consisting of a peak demand charge (PD) and a tariff consisting of a volumetric charge with net-metering (NM), in order to recover the sunk costs of the DSO. The disjoint implementation of three possible distribution tariffs in two countries leads to nine possible scenarios.

The contribution of this work is twofold. First, to the best of our knowledge, we are the first to quantify the spillover effects of distribution grid tariffs. Second, we make a modeling contribution. We develop a long-run market equilibrium model which takes into account distribution tariffs in the decision-making problems of consumers. In the academic literature studying distribution grid tariff design, wholesale markets are typically not modeled and the energy component of the retail tariff is consequently assumed fixed (Schittekatte et al., 2018; Abdelmotteleb et al., 2018). Brown and Sappington (2017, 2018) allow the electricity tariff, including both network and energy charges, to vary, but they model a vertically-integrated utility, not a wholesale market. The application of an equilibrium modeling technique in the field of distribution grid tariff design is novel and, contrary to the aforementioned methodologies, allows analyzing the spillover effects of distribution grid tariffs, as they occur through market interactions.

The remainder of this paper is organised as follows. In Section 2, the market equilibrium model is developed. In Section 3, we present the results of a case study. Finally, we provide policy implications and conclusions in Section 4.

2. Methodology

The model presented in this section is a non-cooperative game, with coupling constraints imposed by distribution cost recovery at country-scale and endogenous determination of the wholesale market price. First, we detail the modeling approach (Section 2.1). Subsequently, we formally define the non-cooperative game in Section 2.2. The mathematical formulation is presented in Section 2.3. Finally, the solution procedure is detailed in Section 2.4.

2.1. Modeling approach

On one hand, our model is inspired by traditional electricity market equilibrium models (Gabriel et al., 2013). The model output mimics the long-run equilibrium in a wholesale electricity market. In our case specifically, the market spans two countries interconnected by a transmission line, in which price-taking generators and consumers participate, facilitated by market clearing agents and a market coupling agent. Market equilibrium models have been often applied to analyze market design and/or policy measures in the power sector. For example, Höschle et al. (2018) and Ehrenmann and Smeers (2011) develop stochastic market equilibrium models to analyze capacity markets. Saguan and Meeus (2014) analyze the costs of renewable energy using a market equilibrium model representing two interconnected countries for four states of the world: with national and international transmission planning, and with and without renewable energy trade. Zhao et al. (2010) analyze the efficiency of multiple systems for allocating emission allowances with a market equilibrium model, representing an energy, capacity and emission allowance market.

On the other hand, our model is inspired by the game-theoretic model of Schittekatte et al. (2018), who formulate a game between residential consumers trying to shift distribution costs to other consumers under a sunk DSO cost recovery constraint. We model a perfectly regulated revenue-constrained DSO that is able to recover its sunk costs by setting the distribution tariff in concert with the NRA. As a result, residential consumers play a non-cooperative game, in which they can shift distribution costs to other consumers. The distribution tariff structure is exogenously set by the NRA before the game, i.e., only the level of the tariff is considered in the non-cooperative game. If a consumer manages to reduce his distribution costs, this leads to an increase of the distribution costs of the other consumers because the DSO can adapt the tariff to ensure cost recovery. Under a peak demand-based tariff structure, for instance, an active consumer may install storage to reduce his peak demand and thus his distribution costs. The DSO, monitored by the NRA, must then increase the distribution tariff to compensate this loss of revenue. This may cause the aforementioned active consumer to adapt his strategy. He could, for instance, install more storage. Finally, in the long-run equilibrium, the tariffs will be set exactly so that all costs are recovered, taking into account the actions of active consumers.

The model output can be interpreted as a generalized Nash equilibrium of a non-cooperative game between the aforementioned agents, i.e., generators, residential consumers, market clearing agents, a market coupling agent and the DSOs. The game is schematically presented in Figure 1.

The model is highly stylized due to, i.a., a number of simplifying assumptions. We assume that all consumers and generators are price-takers and that all demand is inelastic. We consider an energy-only market without a price cap or other market imperfections. Short-term uncertainty and operating reserves are not considered. Both countries are connected by a transmission line with a non-binding capacity. In order to make the location of generating and storage technologies meaningful, however, we add a linear transmission cost.[1] The market is cleared hourly, and we assume that residential consumers pay the hourly wholesale electricity prices for their energy use. They only consider their energy and distribution costs, along with their investments costs. Other cost components, e.g., a retail margin, taxes, etc. are disregarded. Residential consumers are unable to disconnect from the grid. We only consider sunk distribution network costs. This entails that the distribution network costs do not change regardless of the actions of consumers. This sunk cost assumption is justified by (i) massive policy costs being thrust upon DSOs, and (ii) more fundamentally, because the traditional 'fit-and-forget' approach of distribution grid planning has led to over-dimensioned grids with large capital costs (Pollitt, 2018). Finally, we assume that the DSO is perfectly

[1] We choose this cost as such that there is no impact on the costs of consumers and that transmission is never a barrier to install generation and/or DER capacity in a particular country, if there is a clear incentive to do so. In our work, these incentives will follow from the imposed distribution tariff structures. However, the transmission cost will ensure a "logical" distribution of generation and DER capacities if the model - without the transmission costs - would be indifferent to the location of the new investment. If both countries are the same size and have imposed the same distribution tariffs, for instance, the generation and DER capacities will be equal in each country. Without the transmission cost, the location of the generation and DER capacities would be arbitrary in this instance.

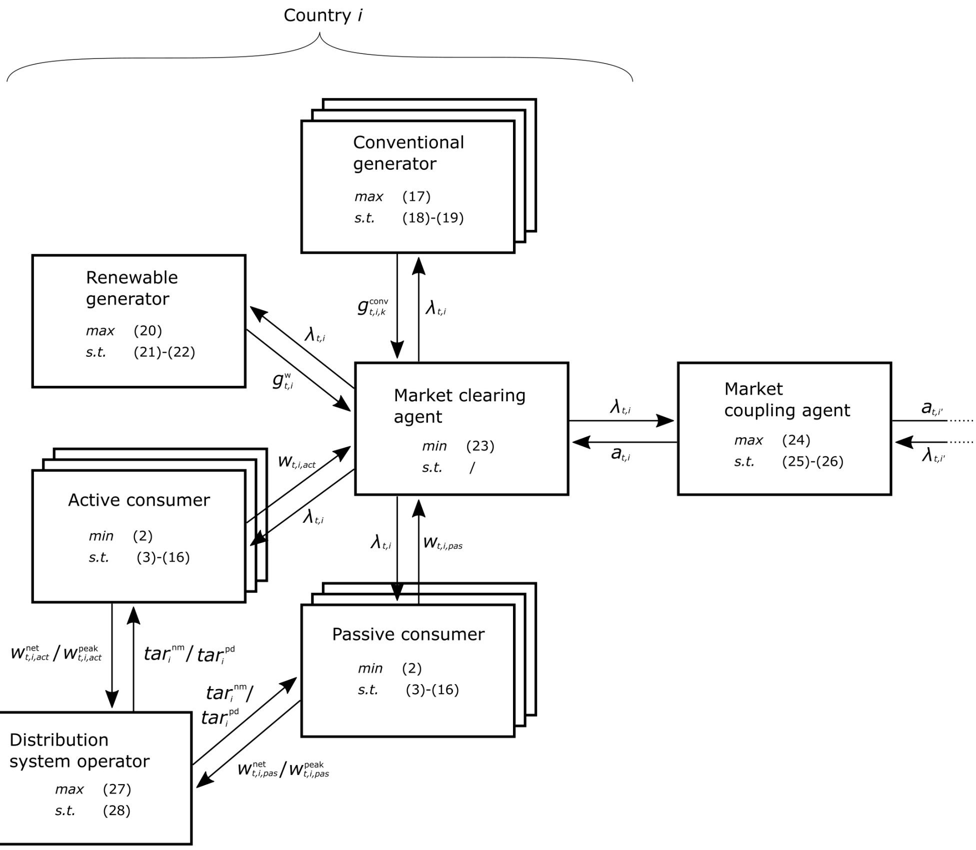

Figure 1: Schematic overview of the non-cooperative game (2)-(28), with references to the optimization problems of the agents (cf. Section 2.3) and the coupling variables. The agents in the second country i' are structured the same as the visualized agents belonging to country i. All agents in one country are linked by the market clearing price, determined hourly by the market clearing agent. Both countries are linked by the market coupling agent who arbitrages between both markets. The residential consumers in each country are linked by the optimization problem of the DSO, who attempts to fulfill his cost recovery annually.

regulated, implying that the NRA's estimation of the DSO's costs correspond to the DSO's actual costs.

2.2. Formal definition of non-cooperative game

In this section, we formally define the non-cooperative game. This general formulation shows that the game can be defined for any number of countries and consumer segments, while it facilitates the mathematical formulation of Section 2.3. We define the set of agents in the non-cooperative game as $\mathcal{A} := (C_{i,j})_{i\in\mathcal{I},j\in\mathcal{J}} \cup (G_{i,k})_{i\in\mathcal{I},k\in\mathcal{K}} \cup (R_i)_{i\in\mathcal{I}} \cup \{MCL_i\}_{i\in\mathcal{I}} \cup \{MCO\} \cup \{DSO_i\}_{i\in\mathcal{I}}$. There are a finite number of representative consumers $C_{i,j}$, each representative consumer representing the $\mathrm{N}_{i,j}$ identical consumers belonging to a certain consumer segment $j \in \mathcal{J}$ in a certain country $i \in \mathcal{I}$. There are a finite number of conventional generators $G_{i,k}$ aggregated per country $i \in \mathcal{I}$ and generator type $k \in \mathcal{K}$. In each country, there is one aggregated renewable (wind) generator R_i. The markets are cleared by national market clearing agents MCL_i and coupled by a market coupling agent MCO. In each country, there is also one DSO, DSO_i, who sets the distribution tariff in that country. For every agent $a \in \mathcal{A}$, $\mathcal{X}_a$ is its set of strategies. Then $\mathcal{X} := \times_{a\in\mathcal{A}}\mathcal{X}_a$ denotes the set of all possible combinations of strategies that can be chosen by the agents in $\mathcal{A}$. Each agent $a \in \mathcal{A}$ has a utility function defined as $\Pi_a : \mathcal{X} \to \mathbb{R}$.

The non-cooperative game between the aforementioned agents is denoted as Γ : $(\mathcal{A}, \mathcal{X}, (\Pi_a)_{a\in\mathcal{A}})$ in which each agent selfishly maximizes its utility Π_a, subject to a set of constraints. As we show in Section 2.3.6, the solution space of each DSO's optimization problem depends on the strategies of the residential consumers. In other words, decision variables of the residential consumers appear in the constraints of the DSO's optimization problem. This requires interpreting this setting as a generalized Nash equilibrium problem. Let χ_{-a} be the vector of strategies of all the agents in $\mathcal{A}$, except agent a. Then, given the strategies of the other agents in $\mathcal{A}$, each agent $a \in \mathcal{A}$ simultaneously solves:

$$\max_{\chi_a\in\mathcal{X}_a(\chi_{-a})} \quad \Pi_a(\chi_a, \chi_{-a}) \tag{1}$$

Each agent thus solves an optimization problem, of which the general form is given by Eq. (1). All agents in each country i are coupled through the optimization problem of the market clearing agent MCL_i who determines the wholesale electricity prices $\lambda_{t,i}$. Both markets are coupled by the market coupling agent MCO who arbitrages between both markets. In addition, residential consumers in each country are coupled through the optimization problem of the national DSO, DSO_i, who sets the distribution tariff. The generalized Nash equilibrium of this problem corresponds to a state in which no agent can unilaterally improve its utility, by adapting its strategy χ_a, given the strategies of the other agents χ_{-a}.

2.3. Mathematical formulation

In this section, the decision-making problems of all agents are presented in detail. The dual variables associated with each constraint are given between brackets. Contrary to the previous section, we move back to the specific setting of our work in which we consider two countries and two consumer segments (active and passive). This allows a straightforward formulation of the optimization problem of the market coupling agent (Section 2.3.5), while the formulations of the optimization problems of the other agents remain general.

2.3.1. Residential consumers

The decision variables of each representative consumer $C_{i,j}$ are his PV investment $cap^{\text{pv}}_{i,j}$, his storage investment $cap^{\text{s}}_{i,j}$, the energy produced by his PV system $g^{\text{pv}}_{t,i,j}$, the energy stored in his storage system $e_{t,i,j}$, the energy charged to or discharged from his storage system $ch_{t,i,j}$ and $dc_{t,i,j}$, the energy withdrawn from or injected into the grid $w_{t,i,j}$[2] and the DSO's billing variables $w^{\text{net}}_{i,j}$ and $w^{\text{peak}}_{i,j}$. Each consumer $C_{i,j}$ solves the optimization problem (2)-(16):

[2]A consumer injects into the grid if $w_{t,i,j} \leqslant 0$.

$$\text{Minimize} \quad \sum_{t\in\mathcal{T}} \lambda_{t,i}\cdot w_{t,i,j} + \mathrm{IC}^{\mathrm{pv}}\cdot cap^{\mathrm{pv}}_{i,j} + \mathrm{IC}^{\mathrm{s}}\cdot cap^{\mathrm{s}}_{i,j} + \mathrm{u}^{\mathrm{fix}}_{i}\cdot tar^{\mathrm{fix}}_{i} + \mathrm{u}^{\mathrm{nm}}_{i}\cdot tar^{\mathrm{nm}}_{i}\cdot w^{\mathrm{net}}_{i,j} + \mathrm{u}^{\mathrm{pd}}_{i}\cdot tar^{\mathrm{pd}}_{i}\cdot w^{\mathrm{peak}}_{i,j} \tag{2}$$

subject to

$$w_{t,i,j} = \mathrm{D}_{t,i,j} + ch_{t,i,j} - dc_{t,i,j} - g^{\mathrm{pv}}_{t}, \quad \forall t\in\mathcal{T} \quad (\alpha_{t,i,j}) \tag{3}$$

$$0 \leqslant g^{\mathrm{pv}}_{t,i,j} \leqslant \mathrm{LF}^{\mathrm{pv}}_{t,i}\cdot cap^{\mathrm{pv}}_{i,j}, \quad \forall t\in\mathcal{T} \quad (\beta^{-}_{t,i,j}, \beta^{+}_{t,i,j}) \tag{4}$$

$$e_{t,i,j} = e_{t-1,i,j} + ch_{t,i,j}\cdot\mathrm{EC} - dc_{t,i,j}/\mathrm{ED}, \quad \forall t\in\mathcal{T}\backslash\{1\} \quad (\gamma_{t,i,j}) \tag{5}$$

$$e_{1,i,j} = cap^{\mathrm{s}}_{i,j}/2 + ch_{1,i,j}\cdot\mathrm{EC} - dc_{1,i,j}/\mathrm{ED}, \quad (\gamma_{1,i,j}) \tag{6}$$

$$e_{T,i,j} = cap^{\mathrm{s}}_{i,j}/2, \quad (\delta_{i,j}) \tag{7}$$

$$0 \leqslant e_{t,i,j} \leqslant cap^{\mathrm{s}}_{i,j}, \quad \forall t\in\mathcal{T} \quad (\epsilon^{-}_{t,i,j}, \epsilon^{+}_{t,i,j}) \tag{8}$$

$$0 \leqslant ch_{t,i,j} \leqslant \mathrm{CR}\cdot cap^{\mathrm{s}}_{i,j}, \quad \forall t\in\mathcal{T} \quad (\zeta^{-}_{t,i,j}, \zeta^{+}_{t,i,j}) \tag{9}$$

$$0 \leqslant dc_{t,i,j} \leqslant \mathrm{CR}\cdot cap^{\mathrm{s}}_{i,j}, \quad \forall t\in\mathcal{T} \quad (\eta^{-}_{t,i,j}, \eta^{+}_{t,i,j}) \tag{10}$$

$$0 \leqslant cap^{\mathrm{pv}}_{i,j} \leqslant \overline{\mathrm{cap}^{\mathrm{pv}}_{i,j}}, \quad (\theta^{-}_{i,j}, \theta^{+}_{i,j}) \tag{11}$$

$$0 \leqslant cap^{s}_{i,j} \leqslant \overline{\mathrm{cap}^{\mathrm{s}}_{i,j}}, \quad (\iota^{-}_{i,j}, \iota^{+}_{i,j}) \tag{12}$$

$$\sum_{t\in\mathcal{T}} w_{t,i,j} \leqslant w^{\mathrm{net}}_{i,j}, \quad (\kappa^{1}_{i,j}) \tag{13}$$

$$0 \leqslant w^{\mathrm{net}}_{i,j}, \quad (\kappa^{2}_{i,j}) \tag{14}$$

$$w_{t,i,j} \leqslant w^{\mathrm{peak}}_{i,j}, \quad \forall t\in\mathcal{T} \quad (\mu^{1}_{t,i,j}) \tag{15}$$

$$-w_{t,i,j} \leqslant w^{\mathrm{peak}}_{i,j}, \quad \forall t\in\mathcal{T}, \quad (\mu^{2}_{t,i,j}) \tag{16}$$

As the demand of each consumer is inelastic, maximizing his utility function corresponds to minimizing his costs. Those costs, given by (2), are equal to the sum of his energy costs (first term), investment costs (second and third term) and distribution costs (fourth, fifth and sixth term). By assumption, the consumer is subjected to the real-time prices on the wholesale market, i.e., his energy costs are the product of the energy consumed during each hour multiplied by the market clearing price $\lambda_{t,i}$. If his consumption is negative, i.e., he injects into the grid, he thus receives the wholesale electricity price for the injected energy. The investment costs of the consumer are the result of investments in PV and storage, depending on the annualized investment costs of these technologies $\mathrm{IC}^{\mathrm{pv}}$ and IC^{s}. With the exception of storage losses, we assume that these DERs do not have operational costs. The NRA of each country i exogenously imposes the distribution tariff structure by setting only one of the binary parameters $\mathrm{u}^{\mathrm{fix}}_{i}$, $\mathrm{u}^{\mathrm{net}}_{i}$ and $\mathrm{u}^{\mathrm{pd}}_{i}$ equal to 1. Under a distribution tariff with a fixed charge ($u^{\mathrm{fix}}_{i} = 1$), consumer $C_{i,j}$ pays a yearly fixed amount to the DSO, equal to tar^{fix}_{i}. Under a distribution tariff structure consisting of a volumetric charge with net-metering ($u^{\mathrm{nm}}_{i} = 1$), the distribution costs of consumer $C_{i,j}$ are proportional to $w^{\mathrm{net}}_{i,j}$, defined by (13)-(14), and the tariff tar^{nm}_{i} in €/kWh. Finally, under a distribution tariff structure consisting of a peak-demand charge ($u^{\mathrm{pd}}_{i} = 1$), the distribution costs of consumer $C_{i,j}$ are proportional to $w^{\text{peak}}_{i,j}$, defined by Eq. (15)-(16), and the tariff tar^{pd}_{i} in €/kW.

Constraint (3) gives the behind-the-meter energy balance of each consumer. The hourly withdrawal from or injection into the grid of a consumer follows from his fixed demand $\mathrm{D}_{t,i,j}$, the energy (dis)charged from his storage system and the energy produced by his PV system. Equation (4) limits the PV production to the installed capacity multiplied with the load factor $\mathrm{LF}^{\text{pv}}_{t,i}$ in each time step. The inequality implies that consumers are able to curtail the output of their PV system. Constraints (5)-(7) determine the evolution of the energy content of the storage system in time. We impose cyclical boundary conditions. Equation (8) limits the energy content to the installed storage capacity. The energy charged/discharged every hour is limited by the installed storage capacity, multiplied with the C-rate CR (Eq. (9)-(10)). Equations (11)-(12) limit the investment in PV and storage respectively. Constraints (13) and (14) define the variable $w^{\text{net}}_{i,j}$ which is used to bill the consumers under the volumetric tariff structure with net-metering. If the net-metering tariff structure is imposed by the NRA ($\mathrm{u}^{\text{nm}}_{i} = 1$), these constraints, along with the presence of $w^{\text{net}}_{i,j}$ in the objective, make sure that $w^{\text{net}}_{i,j}$ is always equal to the net withdrawal over all time steps ($\sum_{t\in\mathcal{T}} w_{t,i,j}$) if the net withdrawal is positive.[3] This implementation corresponds to a net-metering tariff structure with a rolling credit over all time steps $t \in \mathcal{T}$ (Eid et al., 2014). Constraints (15)-(16), along with the presence of $w^{\text{peak}}_{i,j}$ in the objective, ensure that the variable $w^{\text{peak}}_{i,j}$, which is used to bill the consumers under the peak demand-based tariff structure, is always equal to the maximum hourly withdrawal or injection in the period spanned by $t \in \mathcal{T}$ if $\mathrm{u}^{\text{pd}}_{i} = 1$.

2.3.2. Conventional generators

The decision variables of each conventional generator $G_{i,k}$ are its installed capacity $cap^{\text{conv}}_{i,k}$ and its hourly generation $g^{\text{conv}}_{t,i,k}$. Each conventional generator solves the optimization problem (17)-(19):

$$\text{Maximize} \quad \sum_{t\in\mathcal{T}} (\lambda_{t,i} - \mathrm{VC}_k)\cdot g^{\text{conv}}_{t,i,k} - \mathrm{IC}^{\text{conv}}_{k}\cdot cap^{\text{conv}}_{i,k} \tag{17}$$

subject to

$$0 \leqslant g^{\text{conv}}_{t,i,k} \leqslant cap^{\text{conv}}_{i,k}, \quad \forall t\in\mathcal{T} \quad (\nu^{-}_{t,i,k}, \nu^{+}_{t,i,k}) \tag{18}$$

$$0 \leqslant cap^{conv}_{i,k}, \quad (\xi_{i,k}) \tag{19}$$

The objective of each generator (17) is to maximize its profit, equal to its revenues corrected for its operational and investment costs. The revenues depend on the market clearing price $\lambda_{t,i}$. The operational costs are proportional to the variable costs of the generator VC_k while the annualized investment costs are governed by $\mathrm{IC}^{\text{conv}}_{k}$. Constraint (18) limits the production to the installed generation capacity.

[3] If $\mathrm{u}^{\text{nm}}_{i} = 1$, $w^{\text{net}}_{i,j}$ will always be chosen as small as possible, subject to constraints (13)-(14), as that choice minimizes the objective considering the tariff tar^{nm}_{i} is never negative.

2.3.3. Renewable generators

Because each renewable generator R_i can only invest in wind generation, its decision variables are the installed capacity of wind turbines cap_i^{w} and the hourly generation of those wind turbines $g_{t,i}^{\mathrm{w}}$ considering the availability of this resource. Each renewable generator solves the optimization problem (20)-(22):

$$\text{Maximize} \quad \sum_{t \in \mathcal{T}} \lambda_{t,i} \cdot g_{t,i}^{\mathrm{w}} - \mathrm{IC}^{\mathrm{w}} \cdot cap_i^{\mathrm{w}} \tag{20}$$

subject to

$$0 \leqslant g_{t,i}^{\mathrm{w}} \leqslant \mathrm{LF}_{t,i}^{\mathrm{w}} \cdot cap_i^{\mathrm{w}}, \quad \forall t \in \mathcal{T} \quad (o_{t,i}^{-}, o_{t,i}^{+}) \tag{21}$$

$$0 \leqslant cap_i^{\mathrm{w}}, \quad (\pi_i) \tag{22}$$

Similar to conventional generators, the objective of each renewable generator (20) is to maximize its profit, equal to its revenues, which depend on the market clearing, corrected for the investment costs, proportional to the annualized investment costs IC^{w}. We assume that wind generation has no variable costs. Constraint (21) limits the generation to the installed capacity multiplied by the load factor $\mathrm{LF}_{t,i}^{\mathrm{w}}$. The renewable generator can curtail its output.

2.3.4. Market clearing agents

Inspired by Höschle et al. (2018), we define each market clearing agent MCL_i explicitly as an agent who sets the wholesale electricity prices $\lambda_{t,i}$, with the objective of minimizing the imbalances on the national wholesale market. In the objective (23), the market clearing equation of country i at each time step, between brackets, is multiplied by the corresponding market clearing price $\lambda_{t,i}$. In the long-run equilibrium, the market clearing agent MCL_i will set the wholesale electricity prices as such that there is a balance between the sum of residential and non-residential demand ($\mathrm{D}_{t,i}^{\mathrm{nres}}$) and the sum of all generation and import at each time step. There are no constraints, implying that wholesale electricity prices are not capped. The unconstrained optimization problem of MCL_i is described by Eq. (23):

$$\text{Minimize} \quad \sum_{t \in \mathcal{T}} \Big(\sum_{k \in \mathcal{K}} g_{t,i,k}^{\mathrm{conv}} + g_{t,i}^{\mathrm{w}} + a_{t,i} - \mathrm{D}_{t,i}^{\mathrm{nres}} - \sum_{j \in \mathcal{J}} \mathrm{N}_{i,j} \cdot w_{t,i,j} \Big) \cdot \lambda_{t,i} \tag{23}$$

2.3.5. Market coupling agent

Both market clearings are coupled by the market coupling agent MCO who arbitrages perfectly between both countries. Inspired by Hobbs and Helman (2004), we model the market coupling agent as an arbitraging agent with the objective of maximizing its profit from arbitrage, taking into account transmission costs. The decision variables are the energy imported into or exported from each country $a_{t,i}$[4], and the flow over the transmission line f_t. The market coupling agent solves the optimization problem (24)-(26):

[4]If $a_{t,i} \geqslant 0$, country i imports electricity, while a negative $a_{t,i}$ implies export.

$$\text{Maximize} \quad \sum_{t\in\mathcal{T}} \Big(\sum_{i\in\mathcal{I}} (\lambda_{t,i}\cdot a_{t,i}) - \mathrm{CT}\cdot f_t \Big) \tag{24}$$

subject to

$$\sum_{i\in\mathcal{I}} a_{t,i} = 0, \quad \forall t\in\mathcal{T} \quad (\rho_t) \tag{25}$$

$$f_t \geqslant a_{t,i}, \quad \forall t\in\mathcal{T}, i\in\mathcal{I} \quad (\sigma_{t,i}) \tag{26}$$

We assume a non-binding transmission capacity and a small linear transmission cost CT in order to give a small location-specific signal for generation and DER investments. Constraint (25) imposes conservation of energy, entailing that the import in one country equals the export from the other country. Equation (26) determines the absolute electricity flow over the transmission line, which governs the transmission costs.

2.3.6. Distribution system operators

We model each distribution system operator DSO_i as a revenue regulated entity. The decision variables of DSO_i are the tariffs tar_i^{fix}, tar_i^{nm} and tar_i^{pd} that allow cost recovery, dependent on the exogenously set distribution tariff structure (determined by the binary parameters $\mathrm{u}_i^{\mathrm{fix}}$, $\mathrm{u}_i^{\mathrm{nm}}$ and $\mathrm{u}_i^{\mathrm{pd}}$). The optimization problem of DSO_i is described by Eq. (27)-(28):

$$\text{Maximize} \quad \sum_{j\in\mathcal{J}} \mathrm{N}_{i,j}\cdot\big(\mathrm{u}_i^{\mathrm{fix}}\cdot tar_i^{\mathrm{fix}} + \mathrm{u}_i^{\mathrm{nm}}\cdot tar_i^{\mathrm{nm}}\cdot w_{i,j}^{\mathrm{net}} + \mathrm{u}_i^{\mathrm{pd}}\cdot tar_i^{\mathrm{pd}}\cdot w_{i,j}^{\mathrm{peak}}\big) - \mathrm{DC}_i^{\mathrm{tot}} \tag{27}$$

subject to

$$\sum_{j\in\mathcal{J}} \mathrm{N}_{i,j}\cdot\big(\mathrm{u}_i^{\mathrm{fix}}\cdot tar_i^{\mathrm{fix}} + \mathrm{u}_i^{\mathrm{nm}}\cdot tar_i^{\mathrm{nm}}\cdot w_{i,j}^{\mathrm{net}} + \mathrm{u}_i^{\mathrm{pd}}\cdot tar_i^{\mathrm{pd}}\cdot w_{i,j}^{\mathrm{peak}}\big) \leqslant \mathrm{DC}_i^{\mathrm{tot}}, \quad (\phi_i) \tag{28}$$

The DSO's objective (27) is maximizing its profits, i.e. the revenues received from residential consumers via the distribution tariff, corrected for its sunk costs $\mathrm{DC}_i^{\mathrm{tot}}$. However, the DSO's revenue is capped to its costs by the NRA (Eq. (28)). We disregard the profit margin that an NRA would typically allow and assume that the NRA has complete information.[5] The revenue constraint (28) contains decision variables of the residential consumers, $w_{i,j}^{\mathrm{net}}$ and $w_{i,j}^{\mathrm{peak}}$, requiring a generalized Nash equilibrium solution concept as discussed in Section 2.2. The presented formulation always leads to tariffs that ensure cost recovery, i.e., a zero-profit for the DSO, except if cost recovery is infeasible which only occurs if $w_{i,j}^{\mathrm{net}} = 0$ or $w_{i,j}^{\mathrm{peak}} = 0$ for all consumers $C_{i,j}$.[6]

[5]This assumption allows us to use the same cost parameter, $\mathrm{DC}_i^{\mathrm{tot}}$, in both the objective and the revenue constraint. The objective contains the actual costs of the DSO while the revenue constraint contains the NRA's estimation of the DSO's costs.

[6]This result can be derived from the KKT conditions of the optimization problem (27)-(28).

2.4. Solution procedure

We approximate the generalized Nash equilibrium of the non-cooperative game (2)-(28) via an iterative algorithm. The algorithm replaces the DSO optimization problems (27)-(28), because bi-linear terms in those optimization problems do not allow reformulating the complete game. Using this iterative algorithm, we determine the tariffs tar_i^{fix}, tar_i^{nm} and tar_i^{pd} that ensure cost recovery, which is always obtained by the DSO if it is feasible, as discussed in Section 2.3.6.

In each iteration, we solve a simplified version of the original non-cooperative game, containing equations (2)-(26) and considering fixed tariffs tar_i^{fix}, tar_i^{nm} and tar_i^{pd}, hence avoiding non-linearities. The simplified non-cooperative game can be reformulated as an MCP, obtained by deriving the KKT conditions of the optimization problems of all agents. The solution of the MCP can be obtained with the PATH solver (Dirkse and Ferris, 1995) or, under certain conditions, from an equivalent linear optimization problem (Poncelet, 2018). In Appendix A.1, we present the equivalent linear optimization problem (A.1)-(A.22) of the simplified non-cooperative game (2)-(26). To check that the optimization problem is equivalent to the simplified non-cooperative game, we derive the KKT conditions from both models in Appendix A.2. As they are identical, we conclude that both formulations are equivalent. The linear optimization problem can be solved efficiently with an off-the-shelf solver such as Gurobi. We prefer this solution procedure as it is significantly quicker for larger instances than solving the MCP directly with PATH.

In the algorithm, we assume the role of the DSO in each country who sets the distribution tariff in order to recover its sunk costs, taking into account the revenue cap. Under a fixed distribution tariff structure ($\mathrm{u}^{\mathrm{fix}} = 1$), the tariff can easily be set as all residential consumers pay the same amount: $tar_i^{\mathrm{fix}} = \mathrm{DC}_i^{\mathrm{tot}} / \big(\sum_{j \in \mathcal{J}} \mathrm{N}_{i,j}\big)$. The total sunk costs incurred by the DSO are simply divided by the total number of residential consumers in country i. The iterative algorithm is trivial in this case as the reformulated problem (A.1)-(A.22) is solved once with the aforementioned value of tar_i^{fix}. Under a volumetric tariff structure with net-metering ($\mathrm{u}^{\mathrm{nm}} = 1$) or a peak demand-based tariff structure ($\mathrm{u}^{\mathrm{pd}} = 1$), however, it is not trivial to set the distribution tariff as the strategies of active consumers depend on the tariff. We use an iterative algorithm to mimic the tariff-setting process, as proposed by Schittekatte et al. (2018), which allows approximating the generalized Nash equilibrium.

As an example of this iterative process, we provide pseudo-code describing the algorithm assuming that the NRA in country 1 imposes a net-metering tariff structure while the NRA in country 2 imposes a peak demand-based tariff structure. By initializing the tariffs at zero, increasing them in small steps ($\Delta^{\mathrm{tar}^{\mathrm{nm}}}, \Delta^{\mathrm{tar}^{\mathrm{pd}}} \rightarrow 0$) and only considering cases in which there is at least one passive consumer with a non-zero demand in each country, we ensure that the algorithm always converges. A passive consumer cannot adapt his net or peak withdrawal implying that he can never avoid distribution costs. Even in the most extreme case, in which active consumers avoid all distribution costs, there always exists a tariff which ensures that all costs are recovered (in this extreme case, all costs are recovered from the passive consumers). The resulting distribution tariffs are not necessarily the only tariffs fulfilling the cost recovery constraints, but by slowly increasing the tariffs, we ensure that the resulting tariffs are the lowest tariffs that fulfill them.

Algorithm 1: Iterative algorithm for approximating the generalized Nash equilibrium of non-cooperative game (2)-(28).

Input: All parameters belonging to non-cooperative game (2)-(28) ($\mathrm{u}_1^{\mathrm{nm}}=1$; $\mathrm{u}_2^{\mathrm{pd}}=1$)
Output: Generalized Nash equilibrium of (2)-(28)
Initialize tariff in country 1: $tar_1^{\mathrm{nm}} = 0$;
while $\mathrm{DC}_1^{\mathrm{tot}} - \sum_{j\in\mathcal{J}} \mathrm{N}_{1,j} \cdot tar_1^{\mathrm{nm}} \cdot w_{1,j}^{\mathrm{net}} \leqslant \epsilon \cdot \mathrm{DC}_1^{\mathrm{tot}}$ **do**
    Initialize tariff in country 2: $tar_2^{\mathrm{pd}} = 0$;
    while $\mathrm{DC}_2^{\mathrm{tot}} - \sum_{j\in\mathcal{J}} \mathrm{N}_{2,j} \cdot tar_2^{\mathrm{pd}} \cdot w_{2,j}^{\mathrm{peak}} \leqslant \epsilon \cdot \mathrm{DC}_2^{\mathrm{tot}}$ **do**
        Solve (A.1)-(A.22);
        Increase tariff in country 2: $tar_2^{\mathrm{pd}} = tar_2^{\mathrm{pd}} + \Delta^{\mathrm{tar}^{\mathrm{pd}}}$;
    end
    Solve (A.1)-(A.22);
    Increase tariff in country 1: $tar_1^{\mathrm{nm}} = tar_1^{\mathrm{nm}} + \Delta^{\mathrm{tar}^{\mathrm{nm}}}$;
end

3. Results

We analyze the spillover effects of distribution grid tariffs based on a numerical example, described in Section 3.1. In Section 3.2, we give the results of one proxy for welfare and two proxies for DER investments, for nine distribution tariff scenarios, in order to analyze welfare and DER investment spillovers respectively.

3.1. Numerical example

3.1.1. Set-up

We consider two countries and two consumer segments: active and passive consumers in the "reference country" and the "neighboring country". All consumers belonging to the same segment and country are assumed identical. Therefore, all consumers are represented by four representative consumers, as described in Section 2.2. Active consumers are able to invest in PV and storage while passive residential consumers are unable to do so. Consumers may be passive for a variety of reasons: they rent so they cannot make the investment decision, they have a limited budget, etc. We assume that each country consists for 50% of active and 50% of passive consumers. Both countries can only differ in two characteristics: the tariff design which is set by the national regulator and the country size. We analyze two cases: a base case with countries of equal size and a case in which the neighboring country is five times larger (w.r.t. the total number of consumers) than the reference country. The second case is relevant in the European context as there is a large variety of country sizes.

3.1.2. Data

All consumers have identical load profiles $\mathrm{D}_{t,i,j}$, obtained from the 2017 Belgian synthetic load profiles (SLPs) of residential consumers with a yearly demand of 3500 kWh (Synergrid, 2018). Note that synthetic load profiles are average consumer load profiles. Actual consumer load profiles are less smooth and have higher peaks. This will mainly influence the operation and profitability of storage for residential consumers. The investment limits for active consumers ($\overline{\text{cap}^{\text{pv}}}$ and $\overline{\text{cap}^{\text{s}}}$) are set at 5 kW and 10 kWh respectively. If both countries are the same size, both countries have 4.8 million residential consumers, similar to Belgium. Consequently, both countries have 2.4 million active consumers and 2.4 million passive consumers. The non-residential demand $\text{D}^{\text{nres}}_{t,i}$ is calculated by subtracting the residential demand from the total load profile of the Belgian power system in 2017, provided by the Belgian TSO Elia (Elia, 2018). The annual residential demand in each country equals 16.8 TWh (3500 kWh times 4.8 million consumers), compared to a total system load of 87.1 TWh. The system load peak is 13.1 GW. For the case in which the neighboring country is five times larger than the reference country, these quantities are multiplied by five for the neighboring country. The wind and PV load factors $\text{LF}^{\text{w}}_{t,i}$ and $\text{LF}^{\text{pv}}_{t,i}$ are obtained by normalizing the output of the Belgian solar PV and wind turbines in 2017 by the installed capacity, both of which are provided by Elia (Elia, 2018). All simulations are performed on a set of 12 representative days of the year 2017, selected via the method of Poncelet et al. (2017).[7] In order to recover their sunk costs, each DSO needs to recover €400 from each consumer on average.[8]

There is no utility scale PV, i.e., all PV is installed by residential consumers. The installation cost of PV is assumed to be 1000 €/kW with a lifetime of 20 years and a discount rate of 5%. This cost assumption is lower than most estimates of current costs, but as the costs are still decreasing rapidly they are realistic for the near future, especially in Europe. The cost of residential PV up to 5 kW reached 1790 €/kW in Q2 of 2016 in Germany, for instance, coming from 4500 €/kW in 2010 (IRENA, 2017b). For PV systems between 5 and 10 kW, the cost in 2016 was already down to 1550 €/kW.[9] Similar to PV, we assume storage is only installed by residential consumers. The installation cost of storage is assumed to be 200 €/kWh with a lifetime of 10 years and a discount rate of 5%. This cost is in line with the low estimates for 2030 (IRENA, 2017a). We assume that each storage system can be fully charged or discharged in 1 hour, i.e. their C-rate is equal to 1 MW/MWh. The charging and discharging efficiency are both 95%.

All generation besides PV is installed at transmission level. For centralized generation, we use the data of Höschle et al. (2018). There is one renewable generation technology at the transmission level: wind. It has an annualized investment cost of 76 500 €/MW and no variable cost. There are three conventional generation technologies, i.e. base-, mid- and

[7]Poncelet et al. (2017) develop an optimization problem which allows selecting a number of days, along with weights ascribed to each day, that are representative for a whole year. The optimization problem minimizes the difference between the actual duration curve and the approximated duration curve constructed using the selected days, taking into account the weight of each day. The optimization problem can take into account multiple time series. We took into account the load curves of residential consumers, the total system load curve, the wind load factor curve and the solar load factor curve.

[8]The distribution costs of the average consumer in Flanders in 2017 were €393 (VREG, 2017).

[9]In the United States, on the other hand, the costs are significantly higher: 5040 €/kW for PV systems up to 5 kW and 4600 €/kW for PV systems between 5 and 10 kW (IRENA, 2017b). These costs are also rapidly decreasing however.

Technology	Variable cost VC_k (€/MWh)	Annualized investment cost $\mathrm{IC}_k^{\mathrm{conv}}$ (€/MW)
Base	36	138 000
Mid	53	82 000
Peak	76	59 000

Table 1: Variable and investment costs of the considered conventional generation technologies, obtained from Höschle et al. (2018).

peak-load generation. The variable and investment costs of these generation technologies are presented in Table 1. Technical constraints, e.g., ramping, are not taken into account.

As discussed in Section 2.1, there is one transmission line between both countries with a non-binding capacity and a small transmission cost. We set CT = 0.001 €/MWh, which is large enough to give a location-specific investment signal, but does not distort other investment incentives, i.e. distribution tariffs.

3.2. Results

In this section, we discuss the spillover effects in the reference country (R), of distribution grid tariffs in the neighboring country (N), based on three proxies for nine distribution tariff scenarios. The nine scenarios follow from the disjoint implementation of three distribution tariff structures in both countries: a fixed tariff structure (FIX), a volumetric tariff structure with net-metering (NM) and a peak demand-based tariff structure (PD). We distinguish two types of spillovers: 1) welfare spillovers, 2) DER investment spillovers. Figure 2 presents the total annual cost increase of residential consumers in the reference country compared to a central planner reference scenario, serving as proxy for welfare.[10] The total annual costs are the sum of energy, distribution and annualized investment costs of all active and passive consumers in the reference country. Figures 3 and 4 present the total installed PV and storage capacities in the reference country, visualizing the DER investment spillover. The results are displayed for the case in which both countries are of equal size (the black dots) and for the case in which the neighboring country is five times larger than the reference country (the grey dots). The shaded areas in the figures group the three scenarios for which the tariff design in the reference country is the same. In each shaded area, there is one harmonized tariff scenario (in which both countries impose the same tariff design), serving as reference, and two unharmonized tariff scenarios (in which the neighboring country imposes a different tariff design). The welfare and DER investment spillovers in the reference country,

[10] The central planner reference scenario refers to the "optimal" long-run equilibrium state of the electricity system that would be obtained by a social welfare maximizing central planner. It is obtained by solving the equivalent linear optimization problem of the non-cooperative game, (A.1)-(A.22), disregarding distribution costs, i.e., leaving the terms $\sum_{i\in\mathcal{I}}\sum_{j\in\mathcal{J}}(\mathrm{u}_i^{\mathrm{fix}}\cdot\mathrm{tar}_i^{\mathrm{fix}}+\mathrm{u}_i^{\mathrm{net}}\cdot\mathrm{tar}_i^{\mathrm{net}}\cdot w_{i,j}^{\mathrm{net}}+\mathrm{u}_i^{\mathrm{cap}}\cdot\mathrm{tar}_i^{\mathrm{cap}}\cdot w_{i,j}^{\mathrm{peak}})$ out of the objective (A.1). The distribution costs are disregarded by the central planner, because they are sunk. Note that the central planner scenario corresponds to the scenario with a fixed tariff in both countries as we discuss in Section 3.2.1.

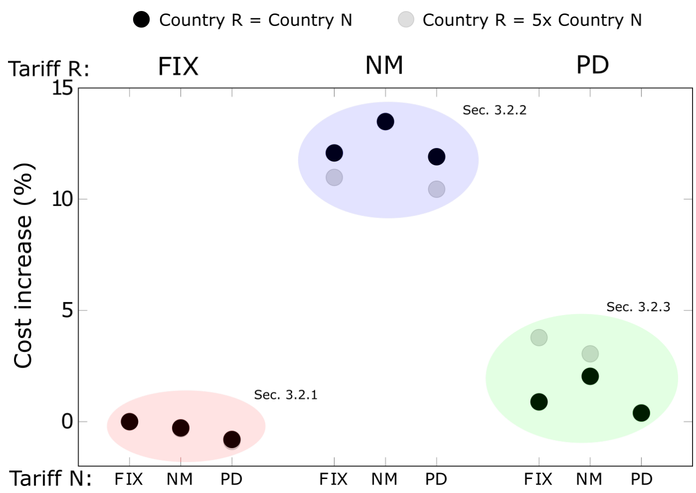

Figure 2: Increase of total annual costs of residential consumers in the reference country (R) compared to a central planner reference case.

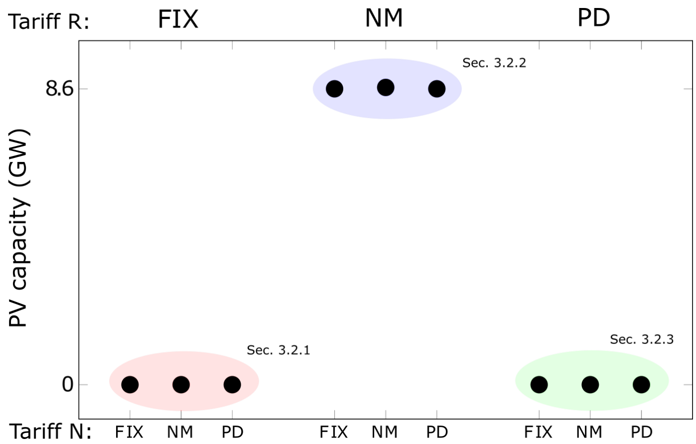

Figure 3: Total PV investments by residential consumers in the reference country (R).

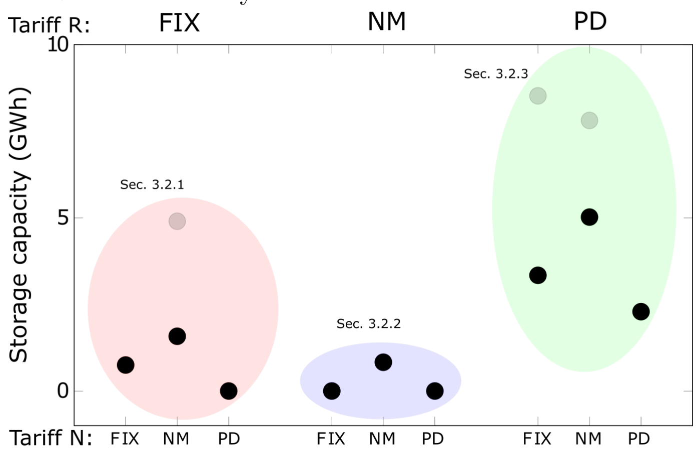

Figure 4: Total storage investments by residential consumers in the reference country (R).

of unharmonized distribution tariffs in the neighboring country, are found by comparing the scenarios with unharmonized tariffs to the harmonized tariff scenario within each shaded area. In Sections 3.2.1-3.2.3, we discuss the results of each shaded area separately.

3.2.1. Fixed tariff in the reference country

We make four observations from Figures 2-4 (shaded, pink areas). First, concerning welfare, the spillover effects of the neighboring country moving from a fixed tariff structure towards a net-metering or peak demand-based tariff structure are positive (Fig. 2). Second, PV investment is not impacted by the tariff design in the neighboring country (Fig. 3). Third, storage investment increases when the neighboring country imposes a net-metering tariff and decreases when the neighboring country imposes a peak demand-based tariff (Fig. 4). Finally, the size of the neighboring country has only a minor impact on the results. Because the spillover effects are connected, we discuss the first three observations for each tariff scenario separately in the following three paragraphs. In the final paragraph, we discuss the impact of country size (i.e., the fourth observation).

Fixed tariff in neighboring country. As indicated in Figure 2, the scenario with harmonized distribution grid tariff structures corresponds to the central planner reference scenario. This results from the set-up of the model, i.e., representing an idealized electricity market, and the sunk cost assumption. Under this assumption, the total distribution network costs $\mathrm{DC}_i^{\mathrm{tot}}$ can never be lowered which implies that only energy cost savings justify DER investment from a social welfare perspective. Under a fixed distribution tariff, active consumers cannot lower their distribution costs which implies that they only invest in PV and/or storage if the subsequent energy cost savings outweigh the investment costs. This leads to the optimal outcome from a social welfare perspective, disregarding other market imperfections. Under our cost assumptions, PV is never installed in the reference country under a fixed distribution tariff (Fig. 3). Storage investment is limited, equalling 0.8 GWh in the scenario with harmonized tariffs. The storage systems are used to perform price arbitrage on the wholesale market.

Peak demand-based tariff in neighboring country. Compared to the previous scenario with harmonized distribution tariff structures, the costs of residential consumers in the reference country decrease with 0.8% (Fig. 2). The peak demand-based tariff incentivizes storage investment in the neighboring country (not visible in Fig. 4) because it allows active consumers to decrease their peak consumption/injection.[11] The extra storage investment in the neighboring country, is not only used for reducing peak consumption/injection, but

[11]Note that these "additional" DER investments, i.e., investments in addition to those that occur in the central planner reference scenario or under the fixed distribution tariff structure, are inefficient from a social welfare perspective in the neighboring country because the total costs for consumers always increase. While the investments of active consumers, from their perspective, are justified by lower energy and distribution costs, the total amount of distribution costs does not decrease under the sunk cost assumption. As a result, the DSO increases tariffs and, consequently, these avoided distribution costs are transferred to the passive consumers in the neighboring country.

also for price arbitrage. Arbitrage decreases the price spreads on the wholesale market. It leads to lower energy costs for passive consumers in the reference country because it reduces demand-weighted average wholesale electricity prices. At the same time, it reduces the arbitrage potential of storage because arbitrage is incentivized by price spreads. This results in active consumers in the reference country not investing in storage (Fig. 4). The subsequent investment cost savings outweigh the energy cost increase of active consumers. Consequently, the total annual costs of both active and passive consumers in the reference country decrease.

Net-metering tariff in neighboring country. Due to the volumetric tariff structure with net-metering, active consumers in the neighboring country are incentivized to invest in 8.6 GW of PV in total (not visible in Fig. 3), because PV production lowers the net consumption of residential consumers. This massive PV investment only results in a small positive spillover in terms of social welfare in the reference country, i.e., the costs of residential consumers are 0.3% lower than in the harmonized tariff scenario (Fig. 2). This result may seem counter-intuitive as many reports and papers show how RES such as PV cause significant decreases in wholesale electricity prices (Paraschiv et al., 2014; Ketterer, 2014). These authors, however, analyze the short-run equilibrium, whereas we look at the long-run equilibrium. In the short term, the rest of the electricity generation system cannot adapt to an increased penetration of RES. As PV has a very low or zero marginal cost, base load power plants set the price more often while peak load power plants are pushed out of the market. Consequently, wholesale electricity prices decrease and conventional generators have difficulties to recover their fixed costs due to the combination of lower prices and fewer running hours. In the perfectly competitive long-run equilibrium, however, the conventional power plant capacities are adapted so that every unit earns a zero profit, typically resulting in more peak- and mid-load capacity and less base-load capacity. Usaola et al. (2009) show, using the screening curve method, that in the long-run equilibrium, wholesale prices do not change with an increasing penetration of wind. Green and Vasilakos (2011) find a similar result using a long-run market equilibrium model. The PV investment in the neighboring country leads to increased storage investments in the reference country, now totalling 1.6 GWh (Fig. 4), because PV increases the price spreads between high- and low-price hours and consequently the arbitrage potential of storage.

Neighboring country five times larger. We observe the same results concerning welfare and PV investment (Fig. 2 and 3). In the scenario with a net-metering tariff in the neighboring country, however, the storage investment increases from 1.6 GWh to 4.9 GWh (Fig. 4) due to an increased impact of net-metering tariff induced PV investment in the neighboring country on the arbitrage potential. Indeed, more PV investment in the neighboring country leads to larger wholesale price spreads, which justifies higher storage investments in the reference country.

3.2.2. Volumetric tariff with net-metering in the reference country

Similar to the previous section, we make four observations from Figures 2-4 (shaded, blue areas). First, the welfare spillovers of the neighboring country moving towards a (unharmonized) fixed or peak demand-based tariff are positive (Fig. 2). Second, there are no PV investment spillovers (Fig. 3). Third, there are negative storage investment spillovers, i.e., storage is only installed when both countries impose a net-metering tariff structure (Fig. 4). Finally, the welfare spillovers are larger if the neighboring country increases in size. Similar to the previous section, we dedicate one paragraph to each tariff scenario, discussing our first three observations for the case with equally sized countries. In the final paragraph, we discuss the impact of country size.

Net-metering tariff in neighboring country. When the NRAs in both countries impose volumetric net-metering tariffs, active consumers in both countries invest in 3.6 kW of PV each, resulting in a total of 8.6 GW in the reference country (Fig. 3). This allows active consumers to generate sufficient energy on an annual basis to avoid all distribution costs, i.e., the annual net consumption of each active consumers is zero. This PV investment is inefficient because the avoided distribution costs are merely transferred to passive consumers through increased distribution tariffs. As a result, the total costs of residential consumers in the reference country are 13.5% higher than in the central planner reference (Fig. 2). A net-metering tariff disincentivizes storage investment because the losses in the storage system increase the net consumption. In the harmonized tariff scenario, however, active consumers in the reference country install 0.8 GWh of storage because the cost reductions arising from price arbitrage outweigh the efficiency losses (Fig. 4).

Fixed tariff in neighboring country. In this scenario, the installed PV capacity in the neighboring country decreases to zero. The PV investment in the reference country, however, remains 8.6 GW since it allows the active consumers to shift all their distribution to the passive consumers (Fig. 3). The storage investment in the reference country decreases to zero (Fig. 4). All 1.6 GWh of storage is now installed in the neighboring country because a fixed distribution tariff does not disincentivize storage like a volumetric net-metering tariff does. The total cost increase of residential consumers in the reference country compared to the central planner reference decreases to 12.1% (Fig. 2). This positive welfare spillover in the reference country is explained by two factors impacting only active consumers: a decrease of storage investment and an increase of the market value of PV, defined as the average electricity price weighted for PV production (Hirth, 2013).[12] Hirth (2013) shows

[12]The market value of PV is the amount of money that an active consumer will receive on average for each MWh of electricity, produced by his PV system, if he would sell this energy on the wholesale market. It gives a more accurate representation of the value of intermittent renewable energy sources than the often used levelized cost of electricity (LCOE) because it takes into account the temporal value of PV (Joskow, 2011). The market value can actually be compared to the LCOE in order to determine if PV investment is efficient. In the optimal case, there is only PV investment if the LCOE is lower than or equal to the market value because it implies that PV producers earn just enough or more than is needed to recover their investment and operational costs. An LCOE higher than the market value of PV indicates that the PV investment is inefficient, i.e., that it would be more efficient to buy from the wholesale market. Under a fixed distribution tariff, consumers get undistorted energy prices, which leads them to the optimal investment decisions. Under a net-metering tariff, consumers may be enticed to invest in PV even if the market value is lower than the LCOE, because they can avoid distribution costs.

empirically, and through numerical modeling, how the market value of PV decreases with increasing PV penetration, defined as the share of PV production in the total amount of produced electricity. This follows from the merit-order effect which entails that more zero marginal cost PV production during a certain time step leads to lower wholesale prices at that time step. In the harmonized tariff scenario, 8.6 GW of PV is installed in each country resulting in a PV penetration of 9.6% and a market value of 35.6 €/MWh. If the neighboring country imposes a fixed distribution tariff, the PV penetration decreases to 4.8%, resulting in a market value of 40.3 €/MWh. Resulting from the increase in market value and the decrease in storage investment, the costs of active consumers in the reference country decrease from 354.7 €/year/consumer in the harmonized tariff scenario to 338.0 €/year/consumer in the scenario with a fixed tariff in the neighboring country. The costs of passive consumers, however, do not change as the PV investment does not impact the average wholesale electricity prices in the long-run (cf. Section 3.2.1). Under a net-metering tariff, the positive welfare spillovers are thus for the active consumers while there is no impact on passive consumers.

Peak demand-based tariff in neighboring country. In this scenario, the positive welfare spillovers are larger than in the previous scenario: the cost increase of residential consumers in the reference country compared to the central planner reference is 11.9% instead of 12.1%. The extra storage investment in the neighboring country (5 GWh under a peak demand-based tariff compared to 1.6 GWh under a fixed tariff), increases the market value of PV (from 40.3 €/MWh to 40.6 €/MWh) and decreases the average wholesale electricity price weighted for the demand of passive consumers (from 54.7 €/MWh to 54.6 €/MWh). Both active and passive consumers in the reference country thus profit from the extra storage investment in the neighboring country, although the impact is limited to 0.2 pp.

Neighboring country five times larger. The mechanisms described in the previous two paragraphs are strengthened because the impact of the tariff structure in the neighboring country on the PV penetration increases. If the neighboring country imposes a fixed tariff, the penetration of 8.6 GW of PV in the reference country is 1.6% instead of 4.8%. Consequently, the market value of PV is 44.7 €/MWh instead of 40.3 €/MWh and the costs of active consumers in the reference country are 323.9 €/year/consumer instead of 338.0 €/year/consumer. If the neighboring country imposes a net-metering tariff, the PV penetration equals 9.6% regardless of the country size, since all active consumers in both countries install 3.6 kW of PV. This leads to the same costs of 354.7 €/year per active consumer in the reference country. The positive welfare spillovers of an unharmonized fixed tariff structure in the neighboring country thus increase if the neighboring country increases in size, i.e., the total cost increase of residential consumers in the reference country compared to the central planner reference decreases from 12.1% to 11% (Fig. 2). The same reasoning applies for the scenario with a peak demand-based tariff structure in the neighboring country.

3.2.3. Peak demand-based tariff in the reference country

We again make four observations from Figures 2-4 (shaded, green areas). We then devote one paragraph to each tariff scenario, discussing the first three observations for the case with equally sized countries, and a final paragraph to the fourth observation. First, the welfare spillovers of an unharmonized tariff structure (a fixed or volumetric net-metering tariff in the neighboring country) are negative (Fig. 2). Second, there is no PV investment in any scenario (Fig. 3). Third, storage investment increases when the neighboring country imposes an unharmonized tariff structure (Fig. 4). Finally, the welfare and storage investment spillovers are larger if the neighboring country increases in size, and the size of the neighboring country determines which tariff structure causes the largest spillover effects.

Peak demand-based tariff in neighboring country. In the harmonized tariff scenario, the storage investment in the reference country equals 2.3 GWh (Fig. 4), while there is no PV investment because PV does not allow reducing the peak consumption that occurs during winter evenings in Belgium (Fig. 3). The cost increase of residential consumers compared to the central planner reference is 0.4% (Fig. 2). The storage investment, and the resulting consumer costs, depend on how active consumers utilize their storage systems. On one hand, active consumers perform price arbitrage, which lowers the total costs for consumers and disincentivizes further storage investments as the arbitrage potential decreases. On the other hand, active consumers use storage to lower their peak demand, subsequently transferring distribution costs to passive consumers, incentivizing further storage investments as the distribution tariffs increase. Both activities can be carried out by the same storage system, but consumers always make a trade-off.[13] In this scenario, we observe a limited amount of storage investment and a limited cost increase for residential consumers in the reference country, implying that the inefficient non-cooperative behavior of active consumers is limited.

Fixed tariff in neighboring country. Compared to the harmonized tariff scenario, the storage investments in the neighboring country decrease. The subsequent increased arbitrage potential of storage results in an increased storage investment of 3.3 GWh in the reference country (Fig. 4). The total cost increase of residential consumers in the reference country also increases to 0.9% (Fig. 2), i.e., there are negative spillovers. This implies that active consumers use this extra storage at least partly to transfer distribution costs to passive consumers.

Net-metering tariff in neighboring country. We observe the same effects as in the previous scenario, but they are more pronounced. The storage investment in the reference country is 5.0 GWh (Fig. 4) and the total cost increase is 2.0% (Fig. 2). At first sight, the stronger spillover effects of the net-metering tariff may seem obvious. This tariff initially increases the arbitrage potential of storage more than a fixed tariff, because it induces PV investment in the neighboring country, leading to increased wholesale market price spreads. When countries are of equal size, the tariff structure in the neighboring country that leads to the greatest initial arbitrage potential of storage ultimately leads to the largest storage investment and the worst manifestation of non-cooperative behavior in the reference country. However, these observations should not be generalized, as we show in the following paragraph.

[13]This trade-off is reflected in the objective function (2) of the consumers' optimization problems, in which they minimize the sum of their investment, distribution and energy costs.

Neighboring country five times larger. We observe more storage investment in the reference country in the unharmonized tariff scenarios if the neighboring country increases in size: 8.5 GWh in the fixed tariff scenario and 7.8 GWh in the net-metering tariff scenario (Fig. 4). This is caused by a dampening of the disincentivizing market force, i.e., the arbitrage potential of storage does not decrease as rapidly with increased storage investment due to the increased size of the combined wholesale market. We also observe larger negative welfare spillovers in the reference country: the cost increase of residential consumers compared to the central planner reference is 3.8% in the fixed tariff scenario and 3.0% in the net-metering tariff scenario, while it remains at 0.4% in the harmonized tariff scenario (Fig. 2). The extra storage in the reference country is thus partly used to transfer more distribution costs to passive consumers. However, the spillover effects of the fixed tariff are larger than those of the volumetric net-metering tariff. In contrast to what we saw previously, a net-metering tariff in the neighboring country does not lead to a further strengthening of the non-cooperative behavior. In this case, the increased arbitrage potential of storage incentivizes consumers in the reference country to focus more on arbitrage instead of peak reduction. In the resulting equilibrium, active consumers install less storage than in the scenario with a fixed tariff. As a result, the energy costs of passive consumers decrease, less distribution costs are transferred to passive consumers and active consumers save on investment costs. This example shows that the long-term spillover effects of distribution tariff structures are difficult to predict when there is a peak demand-based tariff in the reference country impacting storage investment. They are (i) the result of a complex trade-off embedded in the objectives of residential consumers, who minimize both energy and distribution costs, and (ii) dependent on load profiles, technical characteristics of storage systems, country size, etc.

4. Conclusions and policy implications

In this paper, we analyzed the spillover effects of distribution grid tariffs in neighboring countries with coupled wholesale markets. We quantified these effects, complementing the insights of other researchers on the direct effects of distribution grid tariffs, e.g. (Schittekatte et al., 2018; Abdelmotteleb et al., 2018). To this end, we developed a novel market equilibrium model which captures the wholesale market effects of distribution grid tariffs. In a case study, we studied the long-run market equilibrium in nine scenarios, spanning all combinations of three distinct distribution grid tariff designs (a tariff consisting of a fixed charge, a tariff consisting of a volumetric charge with net-metering and a tariff consisting of a peak demand charge) in two countries. We compared the costs of residential consumers and DER investments in different scenarios in order to study the welfare and DER investment spillovers respectively. Our main findings are the following:

1. Concerning welfare, there are positive spillovers in a country that imposes a fixed or net-metering tariff when the neighboring country imposes a different, unharmonized tariff structure. In our case study, the total costs of residential consumers compared to a central planner reference decrease up to -1.6 pp when countries are equal in size and up to -3.0 pp if the neighboring country is five times larger. The welfare spillover

from an unharmonized tariff structure is negative in a country that imposes a peak demand-based tariff. The total costs of residential consumers compared to a central planner reference increase up to +1.6 pp when both countries are equal in size and up to +3.4 pp if the neighboring country is five times larger.

2. Concerning PV investment, there are no spillover effects. Under a fixed or a peak demand-based tariff, there are no PV investments, because PV is not economically viable from a wholesale market perspective under our cost assumptions. Under a net-metering tariff, active consumers massively invest in PV in order to shift distribution costs to passive consumers, but this incentive is so large that it is not impacted by wholesale market effects.

3. Concerning storage investment, there are clear spillover effects of which the direction and magnitude differ widely between different scenarios. In the most extreme scenario in our case study, i.e., a peak demand-based tariff, the total storage investment varies from 2.3 GWh to 5.0 GWh when both countries are equal in size and from 2.3 GWh to 8.5 GWh when the neighboring country is five times larger. Storage investment always depends on the arbitrage potential on the wholesale market. Under a peak demand-based tariff, consumers also use storage for peak reduction which results in a trade-off between arbitrage and peak reduction. This trade-off leads to different results depending on the setting.

These findings indicate that there can be significant positive and negative welfare spillovers of unharmonized distribution tariff structures in coupled wholesale markets. These welfare spillovers are thus not a clear argument for harmonization as a country may be better off with unharmonized tariffs. However, it is important to note that the positive welfare spillovers in one country always follow from – from a system perspective – inefficient DER investments in the neighboring country. This has two implications. First, the total welfare in both countries does not necessarily increase. Second, these inefficient DER investments are the result of distribution grid tariffs implicitly subsidizing DERs, which may be seen as a form of state aid, i.e., another argument for harmonization. Implicit DER subsidies in one country also impact DER investments in the other country. We observe, for instance, less storage investment in the reference country when the neighboring country imposes peak demand-based tariffs, serving as implicit subsidies for storage in the neighboring country.

We focused on the impact of distribution tariffs on DER investments and consumer welfare, while ensuring cost recovery for DSOs. In practice, however, tariff design is a compromise between a multitude of design principles, e.g. cost reflectivity, cost recovery, simplicity, fairness, etc. (CEER, 2017). It is not straightforward to determine the relative importance of these principles. This strengthens the case of the stakeholders that cite "local specificities" as an argument against harmonization, as one country may assign more importance to a certain principle than another country. Therefore, we do not claim to provide a final answer on the question of harmonization of distribution grid tariffs. However, we are the first to quantify some of the elements which are important in this discussion, i.e. welfare and DER investment spillovers.

For future work, in order to deepen our insights, certain assumptions of our analysis could be relaxed. We give two examples. First, relaxing the sunk cost assumption by making a portion of the distribution costs variable and dependent on consumers' actions could lead to interesting insights, since the DSO cost structure is not necessarily the same in each country. Second, we could relax one or more of the assumptions that allows us to model an idealized market, e.g., non-binding transmission capacity, no renewable subsidies, etc. This would give insights in the interaction between the distribution tariff design and other market imperfections. Our analysis can also be extended by including more scenarios with different distribution tariff structures, country sizes, cost parameters, etc. We could also have a closer look at fairness issues by separately analyzing the costs of active and passive consumers. Another direction for future work is to look at the short- and medium-term spillover effects. This would require significant additions to our model with generation capacity being fixed for a certain amount of time, instead of assuming a complete greenfield as we did in this work.

Acknowledgment

The research of Niels Govaerts is supported by a PhD grant provided by the Flemish Institute for Technological Research (VITO). Kenneth Bruninx is a post-doctoral research fellow of the Research Foundation - Flanders (FWO) and the Flemish Institute for Technological Research (VITO).

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Appendix A.

Appendix A.1. Equivalent optimization problem

We follow the method of Poncelet (2018) to derive an optimization problem, equivalent to the "simplified" non-cooperative game (2)-(26), which does not include the optimization problems of the DSOs. Note that the distribution tariffs tar_i^{fix}, tar_i^{nm} and tar_i^{pd} are parameters in this non-cooperative game. The objective of the equivalent optimization problem is equal to the sum of all terms without dual variables in the objectives of the optimization problems of residential consumers $C_{i,j}$ (Eq. (2)), conventional generators $G_{i,k}$ (Eq. (17)), renewable generators R_i (Eq. (20)) and market coupling agent MCO (Eq. (24)). All constraints of the aforementioned optimization problems are constraints of the equivalent optimization problem. The optimization problems of the market clearing agents MCL_i are integrated by including the market clearing equations as constraints, of which the wholesale electricity prices $\lambda_{t,i}$ are dual variables. The equivalent optimization problem is thus described by Eq.(A.1)-(A.22):

$$\begin{aligned}\text{Minimize}\quad & \sum_{i\in\mathcal{I}}\Bigg(\sum_{k\in\mathcal{K}}\Big(\mathrm{IC}_k^{\text{conv}}\cdot cap_{i,k}^{\text{conv}}+\sum_{t\in\mathcal{T}}\mathrm{VC}_k\cdot g_{t,i,k}^{\text{conv}}\Big)+\mathrm{IC}^{\text{w}}\cdot cap_i^{\text{w}}\\ &+\sum_{j\in\mathcal{J}}\mathrm{N}_{i,j}\cdot\Big(\mathrm{IC}^{\text{pv}}\cdot cap_{i,j}^{\text{pv}}+\mathrm{IC}^{\text{s}}\cdot cap_{i,j}^{\text{s}}+\mathrm{u}_i^{\text{fix}}\cdot \mathrm{tar}_i^{\text{fix}}\\ &+\mathrm{u}_i^{\text{nm}}\cdot\mathrm{tar}_i^{\text{nm}}\cdot w_{i,j}^{\text{net}}+\mathrm{u}_i^{\text{pd}}\cdot\mathrm{tar}_i^{\text{pd}}\cdot w_{i,j}^{\text{peak}}\Big)\Bigg)+\sum_{t\in\mathcal{T}}\mathrm{CT}\cdot f_t\end{aligned}\tag{A.1}$$

subject to

$$w_{t,i,j}=\mathrm{D}_{t,i,j}+ch_{t,i,j}-dc_{t,i,j}-g_t^{\text{pv}},\quad \forall t\in\mathcal{T},i\in\mathcal{I},j\in\mathcal{J}\quad(\alpha_{t,i,j})\tag{A.2}$$

$$0\leqslant g_{t,i,j}^{\text{pv}}\leqslant \mathrm{LF}_{t,i}^{\text{pv}}\cdot cap_{i,j}^{\text{pv}},\quad \forall t\in\mathcal{T},i\in\mathcal{I},j\in\mathcal{J}\quad(\beta_{i,j}^{-},\beta_{i,j}^{+})\tag{A.3}$$

$$e_{t,i,j}=e_{t-1,i,j}+ch_{t,i,j}\cdot\mathrm{EC}-dc_{t,i,j}/\mathrm{ED},\quad \forall t\in\mathcal{T}\backslash\{1\},i\in\mathcal{I},j\in\mathcal{J}\quad(\gamma_{t,i,j})\tag{A.4}$$

$$e_{1,i,j}=cap_{i,j}^{\text{s}}/2+ch_{1,i,j}\cdot\mathrm{EC}-dc_{1,i,j}/\mathrm{ED},\quad \forall i\in\mathcal{I},j\in\mathcal{J}\quad(\gamma_{1,i,j})\tag{A.5}$$

$$e_{T,i,j}=cap_{i,j}^{\text{s}}/2,\quad \forall i\in\mathcal{I},j\in\mathcal{J}\quad(\delta_{i,j})\tag{A.6}$$

$$0\leqslant e_{t,i,j}\leqslant cap_{i,j}^{\text{s}},\quad \forall t\in\mathcal{T},i\in\mathcal{I},j\in\mathcal{J}\quad(\epsilon_{t,i,j}^{-},\epsilon_{t,i,j}^{+})\tag{A.7}$$

$$0\leqslant ch_{t,i,j}\leqslant \mathrm{CR}\cdot cap_{i,j}^{\text{s}},\quad \forall t\in\mathcal{T},i\in\mathcal{I},j\in\mathcal{J}\quad(\zeta_{t,i,j}^{-},\zeta_{t,i,j}^{+})\tag{A.8}$$

$$0\leqslant dc_{t,i,j}\leqslant \mathrm{CR}\cdot cap_{i,j}^{\text{s}},\quad \forall t\in\mathcal{T},i\in\mathcal{I},j\in\mathcal{J}\quad(\eta_{t,i,j}^{-},\eta_{t,i,j}^{+})\tag{A.9}$$

$$0\leqslant cap_{i,j}^{\text{pv}}\leqslant \overline{\mathrm{cap}_{i,j}^{\text{pv}}},\quad \forall i\in\mathcal{I},j\in\mathcal{J}\quad(\theta_{i,j}^{-},\theta_{i,j}^{+})\tag{A.10}$$

$$0\leqslant cap_{i,j}^{\text{s}}\leqslant \overline{\mathrm{cap}_{i,j}^{\text{s}}},\quad \forall i\in\mathcal{I},j\in\mathcal{J}\quad(\iota_{i,j}^{-},\iota_{i,j}^{+})\tag{A.11}$$

$$\sum_{t\in\mathcal{T}}w_{t,i,j}\leqslant w_{i,j}^{\text{net}},\quad \forall i\in\mathcal{I},j\in\mathcal{J}\quad(\kappa_{i,j}^{1})\tag{A.12}$$

$$0\leqslant w_{i,j}^{\text{net}},\quad \forall i\in\mathcal{I},j\in\mathcal{J}\quad(\kappa_{i,j}^{2})\tag{A.13}$$

$$w_{t,i,j}\leqslant w_{i,j}^{\text{peak}},\quad \forall t\in\mathcal{T},i\in\mathcal{I},j\in\mathcal{J}\quad(\mu_{t,i,j}^{1})\tag{A.14}$$

$$-w_{t,i,j} \leqslant w^{\text{peak}}_{i,j}, \quad \forall t \in \mathcal{T}, i \in \mathcal{I}, j \in \mathcal{J} \quad (\mu^2_{t,i,j}) \tag{A.15}$$

$$0 \leqslant g^{\text{conv}}_{t,i,k} \leqslant cap^{\text{conv}}_{i,k}, \quad \forall t \in \mathcal{T}, i \in \mathcal{I}, k \in \mathcal{K} \quad (\nu^-_{t,i,k}, \nu^+_{t,i,k}) \tag{A.16}$$

$$0 \leqslant cap^{\text{conv}}_{i,k}, \quad \forall i \in \mathcal{I}, k \in \mathcal{K} \quad (\xi_{i,k}) \tag{A.17}$$

$$0 \leqslant g^{\text{w}}_{t,i} \leqslant \text{LF}^{\text{w}}_{t,i} \cdot cap^{\text{w}}_i, \quad \forall t \in \mathcal{T}, i \in \mathcal{I} \quad (o^-_{t,i}, o^+_{t,i}) \tag{A.18}$$

$$0 \leqslant cap^{\text{w}}_i, \quad \forall i \in \mathcal{I} \quad (\pi_i) \tag{A.19}$$

$$\sum_{i \in \mathcal{I}} a_{t,i} = 0, \quad \forall t \in \mathcal{T} \quad (\rho_t) \tag{A.20}$$

$$f_t \geqslant a_{t,i}, \quad \forall t \in \mathcal{T}, i \in \mathcal{I} \quad (\sigma_{t,i}) \tag{A.21}$$

$$\sum_{k \in \mathcal{K}} g^{\text{conv}}_{t,i,k} + g^{\text{w}}_{t,i} + a_{t,i} = \text{D}^{\text{nres}}_{t,i} + \sum_{j \in \mathcal{J}} \text{N}_{i,j} \cdot w_{t,i,j}, \quad \forall t \in \mathcal{T}, i \in \mathcal{I} \quad (\lambda_{t,i}) \tag{A.22}$$

Appendix A.2. KKT conditions

The constraints of the optimization problem (A.2)-(A.22), along with stationarity equations (A.23)-(A.38) and complementary slackness conditions (A.39)-(A.61), form the KKT conditions of optimization problem (A.1)-(A.22). These KKT conditions can also be derived from the "simplified" non-cooperative game (2)-(26) which shows that both formulations are equivalent.

$$-\alpha_{t,i,j} + \kappa^1_{i,j} + \mu^1_{t,i,j} - \mu^2_{t,i,j} + \text{N}_{i,j} \cdot \lambda_{t,i} = 0, \quad \forall t \in \mathcal{T}, i \in \mathcal{I}, j \in \mathcal{J} \tag{A.23}$$

$$\text{N}_{i,j} \cdot \text{IC}^{\text{pv}} - \sum_{t \in \mathcal{T}} \beta^+_{t,i,j} \cdot \text{LF}^{\text{pv}}_{t,i} - \theta^-_{i,j} + \theta^+_{i,j} = 0, \quad \forall i \in \mathcal{I}, j \in \mathcal{J} \tag{A.24}$$

$$\text{N}_{i,j} \cdot \text{IC}^{\text{s}} - \sum_{t \in \mathcal{T}} \left(\epsilon^+_{t,i,j} + \text{CR}(\zeta^+_{t,i,j} + \eta^+_{t,i,j})\right) + (\gamma_{1,i,j} + \delta_{i,j})/2 - \iota^-_{i,j} + \iota^+_{i,j} = 0, \quad \forall i \in \mathcal{I}, j \in \mathcal{J} \tag{A.25}$$

$$-\alpha_{t,i,j} - \beta^-_{t,i,j} + \beta^+_{t,i,j} = 0, \quad \forall t \in \mathcal{T}, i \in \mathcal{I}, j \in \mathcal{J} \tag{A.26}$$

$$-\gamma_{t,i,j} + \gamma_{t+1,i,j} - \epsilon^-_{t,i,j} + \epsilon^+_{t,i,j} = 0, \quad \forall t \in \mathcal{T} \backslash \{T\}, i \in \mathcal{I}, j \in \mathcal{J} \tag{A.27}$$

$$-\gamma_{T,i,j} - \delta_{i,j} - \epsilon^-_{T,i,j} + \epsilon^+_{T,i,j} = 0, \quad \forall i \in \mathcal{I}, j \in \mathcal{J} \tag{A.28}$$

$$\alpha_{t,i,j} + \gamma_{t,i,j} \cdot \text{EC} - \zeta^-_{t,i,j} + \zeta^+_{t,i,j} = 0, \quad \forall t \in \mathcal{T}, i \in \mathcal{I}, j \in \mathcal{J} \tag{A.29}$$

$$-\alpha_{t,i,j} - \gamma_{t,i,j}/\text{ED} - \eta^-_{t,i,j} + \eta^+_{t,i,j} = 0, \quad \forall t \in \mathcal{T}, i \in \mathcal{I}, j \in \mathcal{J} \tag{A.30}$$

$$\text{N}_{i,j} \cdot \text{u}^{\text{nm}}_i \cdot \text{tar}^{\text{nm}}_i - \kappa^1_{i,j} - \kappa^2_{i,j} = 0, \quad \forall i \in \mathcal{I}, j \in \mathcal{J} \tag{A.31}$$

$$\text{N}_{i,j} \cdot \text{u}^{\text{pd}}_i \cdot \text{tar}^{\text{pd}}_i - \sum_{t \in \mathcal{T}} (\mu^1_{t,i,j} + \mu^2_{t,i,j}) = 0, \quad \forall i \in \mathcal{I}, j \in \mathcal{J} \tag{A.32}$$

$$\text{VC}_k - \lambda_{t,i} - \nu^-_{t,i,k} + \nu^+_{t,i,k} = 0, \quad \forall t \in \mathcal{T}, i \in \mathcal{I}, k \in \mathcal{K} \tag{A.33}$$

$$\text{IC}^{\text{conv}}_k - \sum_{t \in \mathcal{T}} \nu^+_{t,k,i} - \xi_{i,k} = 0, \quad \forall i \in \mathcal{I}, k \in \mathcal{K} \tag{A.34}$$

$$-\lambda_{t,i} - o^-_{t,i} + o^+_{t,i} = 0, \quad \forall t \in \mathcal{T}, i \in \mathcal{I} \tag{A.35}$$

$$\mathrm{IC}^{\mathrm{w}} - \sum_{t\in\mathcal{T}} o^{+}_{t,i}\cdot\mathrm{LF}^{\mathrm{w}}_{t,i} - \pi_i = 0, \tag{A.36}$$

$$-\lambda_{t,i} - \rho_t + \sigma_{t,i} = 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I} \tag{A.37}$$

$$\mathrm{CT} - \sum_{i\in\mathcal{I}} \sigma_{t,i} = 0, \quad \forall t\in\mathcal{T} \tag{A.38}$$

$$0 \leq \beta^{-}_{t,i,j} \perp g^{\mathrm{pv}}_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.39}$$

$$0 \leq \beta^{+}_{t,i,j} \perp \mathrm{LF}^{\mathrm{pv}}_{t,i}\cdot cap^{\mathrm{pv}}_{i,j} - g^{\mathrm{pv}}_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.40}$$

$$0 \leq \epsilon^{-}_{t,i,j} \perp e_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.41}$$

$$0 \leq \epsilon^{+}_{t,i,j} \perp cap^{\mathrm{s}}_{i,j} - e_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.42}$$

$$0 \leq \zeta^{-}_{t,i,j} \perp ch_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.43}$$

$$0 \leq \zeta^{+}_{t,i,j} \perp \mathrm{CR}\cdot cap^{\mathrm{s}}_{i,j} - ch_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.44}$$

$$0 \leq \eta^{-}_{t,i,j} \perp dc_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.45}$$

$$0 \leq \eta^{+}_{t,i,j} \perp \mathrm{CR}\cdot cap^{\mathrm{s}}_{i,j} - dc_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.46}$$

$$0 \leq \theta^{-}_{i,j} \perp cap^{\mathrm{pv}}_{i,j} \geq 0, \quad \forall i\in\mathcal{I}, j\in\mathcal{J} \tag{A.47}$$

$$0 \leq \theta^{+}_{i,j} \perp \overline{\mathrm{cap}^{\mathrm{pv}}_{i,j}} - cap^{\mathrm{pv}}_{i,j} \geq 0, \quad \forall i\in\mathcal{I}, j\in\mathcal{J} \tag{A.48}$$

$$0 \leq \iota^{-}_{i,j} \perp cap^{\mathrm{s}}_{i,j} \geq 0, \quad \forall i\in\mathcal{I}, j\in\mathcal{J} \tag{A.49}$$

$$0 \leq \iota^{+}_{i,j} \perp \overline{\mathrm{cap}^{\mathrm{s}}_{i,j}} - cap^{\mathrm{s}}_{i,j} \geq 0, \quad \forall i\in\mathcal{I}, j\in\mathcal{J} \tag{A.50}$$

$$0 \leq \kappa^{1}_{i,j} \perp w^{\mathrm{net}}_{i,j} - \sum_{t\in\mathcal{T}} w_{t,i,j} \geq 0, \quad \forall i\in\mathcal{I}, j\in\mathcal{J} \tag{A.51}$$

$$0 \leq \kappa^{2}_{i,j} \perp w^{\mathrm{net}}_{i,j} \geq 0, \quad \forall i\in\mathcal{I}, j\in\mathcal{J} \tag{A.52}$$

$$0 \leq \mu^{1}_{t,i,j} \perp w^{\mathrm{peak}}_{i,j} - w_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.53}$$

$$0 \leq \mu^{2}_{t,i,j} \perp w^{\mathrm{peak}}_{i,j} + w_{t,i,j} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, j\in\mathcal{J} \tag{A.54}$$

$$0 \leq \nu^{-}_{t,i,k} \perp g^{\mathrm{conv}}_{t,i,k} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, k\in\mathcal{K} \tag{A.55}$$

$$0 \leq \nu^{+}_{t,i,k} \perp cap^{\mathrm{conv}}_{i,k} - g^{\mathrm{conv}}_{t,i,k} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I}, k\in\mathcal{K} \tag{A.56}$$

$$0 \leq \xi_{i,k} \perp cap^{\mathrm{conv}}_{i,k} \geq 0, \quad \forall i\in\mathcal{I}, k\in\mathcal{K} \tag{A.57}$$

$$0 \leq o^{-}_{t,i} \perp g^{\mathrm{w}}_{t,i} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I} \tag{A.58}$$

$$0 \leq o^{+}_{t,i} \perp \mathrm{LF}^{\mathrm{w}}_{t,i}\cdot cap^{w}_{i} - g^{\mathrm{w}}_{t,i} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I} \tag{A.59}$$

$$0 \leq \pi_i \perp cap^{\mathrm{w}}_{i} \geq 0, \quad \forall i\in\mathcal{I} \tag{A.60}$$

$$0 \leq \sigma_{t,i} \perp f_t - a_{t,i} \geq 0, \quad \forall t\in\mathcal{T}, i\in\mathcal{I} \tag{A.61}$$

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