Energy Economics 158 (2026) 109316

Contents lists available at ScienceDirect

Energy Economics

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

CAPEX vs FLEX: The optimal investment mix to integrate decentralized electricity production[☆]

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ARTICLE INFO

JEL classification:
Q4
L94
L51

Keywords:
Decentralized production
Prosumers
Electricity network
Externality
Investment
Regulation

ABSTRACT

Decentralized production increases grid congestion, forcing solar panels to disconnect to prevent over-voltage, a negative externality linked to installed capacity that limits system penetration. Key solutions include network reinforcement (Capex), and investing in flexibility resources (Flex) to boost self-consumption. Using an agent-based model with prosumers, a retailer, and a DSO, we study the trade-off between Capex and Flex by linking a disconnection probability to these investments. Our results indicate that, due to the externality, market outcomes feature excessive Capex and insufficient Flex compared to the optimal mix. While tariff adjustments and Flex subsidies can help, challenges remain because of information asymmetry and heterogeneity.

1. Introduction

The energy transition is exerting unprecedented pressure on electrical grids, which were originally designed for more predictable and centralized energy flows. The rise of decentralized energy systems, particularly solar and wind power, necessitates adaptive solutions to manage their intermittency and maintain grid stability (Hsieh and Anderson, 2017). The increasing electrification of heating and mobility further intensifies the demands on low voltage grids. As a result, electricity flows in all directions, and investments in decentralized production and network planning lack coordination.

Decentralized production units (DPUs), like rooftop solar panels, offer significant benefits to prosumers, including cost savings through self-consumption and additional revenue from grid injections. However, from the perspective of distribution system operators (DSOs), while self-consumption reduces operational costs, energy injections during peak demand can result in additional costs. This dichotomy is particularly evident in regions with high solar energy penetration.

A significant issue arising from high solar PV penetration is inverter disconnection due to overvoltage events. Overvoltage is typically a cyclical or short-term issue that arises intermittently rather than persistently. It occurs when the voltage levels in the electrical grid momentarily exceed safe operational limits due to rapid fluctuations in electricity generation or other grid conditions. This phenomenon triggers protective mechanisms, such as inverter disconnections in solar PV systems, to prevent equipment damage and ensure grid stability. Such disconnections result in production and financial losses for prosumers, who must purchase electricity from the grid during these periods to power essential appliances.[1] The likelihood of overvoltage increases with higher solar PV capacity, leading to more frequent inverter disconnections. This situation represents a negative externality, as the actions of individual prosumers can adversely impact others connected to the same grid line, particularly those at the end of the lines, who are more exposed to disconnections.

[☆] The authors thank participants at the 2nd Conference on Decentralized Energy Systems, (Rouen, 2024), 40th JMA (2024), 3rd RENEL Annual Conference and the seminar attendance at Young Energy Economists and Engineers Seminar (Leuven), Montpellier, HEC Liege, Ph.D. Workshop on Energy Systems (Brussels), for their helpful comments and suggestions. This work is part of the RESA chair at HEC Liege.

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[1] Inverter disconnection is a safety and automatic response to overvoltage. It should be distinguished from PV curtailment, which usually refers to an intentional reduction of power output for technical or economic reasons. For residential PV installations, DSOs usually do not have the power to curtail PV injection in case of congestion (Mateo et al., 2017).

https://doi.org/10.1016/j.eneco.2026.109316
Received 15 July 2025; Received in revised form 26 January 2026; Accepted 25 March 2026

Empirical evidence shows that voltage-induced disconnection of decentralized photovoltaic generation is not merely a theoretical concern but a recurring issue in several electricity systems with high distributed energy resource penetration. In Belgium, distribution system operators have publicly acknowledged the problem. In Flanders (Belgium) where there are close to 1 million solar installations, the DSO Fluvius received 5042 complaints related to inverter disconnections in 2023. In response, the operator implemented a targeted action plan combining short-term operational measures and longer-term grid investments. Ghiani and Pilo (2014), using high-frequency measurements at inverter terminals in an Italian low-voltage network, show that voltage levels during peak PV production frequently exceeded the EN 50160 standard, triggering repeated inverter disconnections and leading to both energy losses and accelerated equipment degradation. Evidence from high-penetration systems outside Europe is also consistent. In Australia, where rooftop PV adoption exceeds one-third of households, network constraints result in average residential PV curtailment of around 1.5 percent of annual generation, with losses reaching up to 25 percent in some locations. Using real-world data from South Australia, Yildiz et al. (2023) confirm these findings and show that curtailment losses are significantly lower when PV systems are coupled with battery storage, highlighting the role of flexibility in mitigating grid constraints. Earlier evidence from Japan (Ueda et al., 2008) and Hawaii, USA (Giraldez Miner et al., 2018) suggests more limited average losses, but still documents localized and time-specific voltage-related disconnections in areas with high PV concentration. Taken together, these observations illustrate that disconnection of small-scale residential PVs are empirically relevant outcomes of distribution grid congestion and voltage management limits, and that their magnitude depends critically on network characteristics, local PV density, and the availability of flexibility solutions.

To address this challenge, there are two possible strategies. The traditional approach involves reinforcing grid components and expanding network capacity (CAPEX), which entails substantial investments for DSOs. Alternatively, flexibility solutions (FLEX) can be implemented by residential prosumers to mitigate overloading and voltage limit violations. Flexibility services include load displacement, smart load management, or storage using a residential battery. Furthermore, electric vehicles (EVs) can be used to modulate consumption and provide flexibility to the grid (Knezović et al., 2015). As flexibility can reduce the need for investment in network expansion, the two solutions, Capex and Flex, should be used in combination to efficiently integrate DPUs into the distribution grid (Mateo et al., 2017; Nouicer et al., 2023).[2]

To achieve this goal, there is a need to adapt regulatory frameworks to accommodate distributed energy. This requires to design appropriate network tariffs for the power exchange on the low voltage grid (Nouicer et al., 2023; Brown and Sappington, 2017; Gautier et al., 2018; Hoarau and Perez, 2019). Distribution tariffs should guarantee that the DSOs recover their costs while providing adequate incentives for investment both for the DSOs and the prosumers. Fairness and cost-reflectiveness are other dimensions that regulators should take into account (Abdelmotteleb et al., 2017).

In this paper, we develop a theoretical model similar to Gautier et al. (2018), featuring prosumers, traditional consumers, competitive electricity retailers, and a DSO overseeing the entire system. In our model, the prosumers' inverters might be disconnected due to over-voltage, in which case their DPUs do not produce.

The novelty of this paper is to consider PV disconnection as a congestion externality in an economic model. We construct a probability of inverter disconnection, which depends on the total power injection on the local grid by the prosumers. As disconnection depends on the total power injection, prosumers exert a negative externality on each other. This probability can be reduced by a Capex investment made by the DSO to reinforce the line. Prosumers can invest in Flex to reduce their injections, particularly during overvoltage events, thereby decreasing the probability of disconnection on the line.

We identify the optimal mix of investment between Capex and Flex and assess whether market mechanisms provide sufficient incentives for both types of investments. We show that this first-best solution cannot be implemented with cost-reflective grid tariffs and competitive energy prices, as prosumers fail to take into account the externality they exert on each other. The decentralized solution leads to too little investment in flexibility, partially compensated by higher investments in network reinforcement.

Next, we explore the instruments available to restore efficient investment, particularly modified grid tariffs and subsidies for Flex investments. Subsidies could be used to compensate for the externality, a classical Pigouvian solution to the problem. Modified grid tariffs can be used to deter massive injections into the grid, making self-consumption more profitable for prosumers and fostering incentives to invest in Flex. However, manipulating grid tariffs may have redistributive consequences, especially for non-prosumers.

Considering heterogeneous prosumers that are not exposed to the same probability of disconnection, which is usually location-specific, the optimal policy should be implemented with individualized subsidies which might be difficult to implement in practice. We then discuss a second-best solution where subsidies are uniform but this fails to restore the first best.

The probability of disconnection varies over time and the use of Flex services should be adapted to this time-varying disconnection probability. Therefore, the optimal Flex investment consists in an optimal battery capacity and an optimal charging/discharging path. We show that subsidies can provide incentives for capacity while time-variant tariffs can provide incentives for an optimal use of Flex. Finally, we discuss the impact of inverter disconnection on the decision to invest in solar PV and on the sizing of the installations. We show that prosumers fail to take into account the impact of their investment on the disconnection probability and they tend to overinvest in decentralized production.

The paper is organized as follow. We review the literature in Section 2. We present the main elements of our model in Section 3. In Section 4, we derive the Capex and Flex investments' decisions for the first-best and decentralized market outcomes. We discuss grid tariffs manipulation and Flex subsidization as instruments to correct the externality problem and restore the first best in Section 5. In Section 6, we present three extensions of the model and Section 7 concludes. All the proofs are relegated to Appendix.

2. Literature review

Integration challenges in decentralized electricity production have been extensively studied for over a decade. Economic literature explores various aspects like incentives for investing in DPU, tariff structures, and system financing. For instance, Eid et al. (2014) focused on cost recovery and cross subsidies related to net-metering, highlighting how prosumers inject surplus power into the grid, impacting energy tariffs and reducing utility revenues globally. Similarly, Brown and Sappington (2017) argued against net metering for intermittent DPUs, advocating capacity charges that accurately reflect infrastructure costs. Furthermore, Gautier et al. (2018) used agent-based modeling to compare net-metering with net-purchasing systems, finding net-metering leads to oversized DPU installations and cross-subsidies.

However, this literature overlooks the physical constraints and drawbacks of increasing DPU penetration on system capacity. While transitioning to DPUs aims to reduce greenhouse gas emissions from fossil fuels, it also raises concerns about network impacts beyond operational costs. According to Uzum et al. (2020), increased DPU

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[2] Another possibility for the DSO is to organize a local flexibility market where consumers and prosumers would trade the right to withdraw and inject power, see for instance (Vassallo et al., 2025).

penetration, such as solar panels, poses challenges like power loss, reverse power flow, and voltage fluctuations, affecting overall voltage quality. Moreover, Benzerga et al. (2021) highlights capacity issues, particularly at 45% penetration for photovoltaic installations and 4% for EV chargers, indicating broader implications for DSO in managing real-world scenarios and externalities generated by DPU investments.

One of the simplest ways to mitigate the impact of decentralized generation is to increase self-consumption among prosumers, thereby reducing the amount of surplus electricity fed into the grid. Beyond this, the literature identifies two main categories of investment to support the energy transition: capital expenditures (Capex) and flexibility services (Flex). Capex investments focus on strengthening the physical infrastructure of distribution networks to increase their capacity to host distributed energy resources. Mateo et al. (2017) provides a detailed listing of Capex investments by distribution system operators (DSOs), including traditional reinforcement measures, often referred to as “copper-and-iron” solutions, that address voltage and thermal constraints caused by high levels of photovoltaic (PV) generation. These involve upgrading cables, transformers, and other grid components. However, relying solely on such infrastructure upgrades can lead to rising long-term costs. Other technical options include on-load tap changers, which adjust transformer voltage levels but often lack real-time responsiveness. More advanced systems, such as dynamic voltage control at high-voltage/medium-voltage (HV/MV) substations, offer faster response but require comprehensive grid monitoring. Additional solutions include static VAR compensators to manage reactive power, booster transformers to address voltage drops, and network reconfiguration techniques that improve load balancing. Together, these investments enhance grid performance and support the integration of decentralized renewable energy sources.

In contrast, flexible investments identified in the literature contribute significantly to grid stability. Storage devices, particularly batteries, play a crucial role. Continued advancements in battery technology and their deployment offer a pathway to affordable renewable energy solutions (Kittner et al., 2017). For instance, providing 9 kWh batteries to each household in residential grids can mitigate voltage issues caused by high PV penetration, reducing curtailment by over 60% (Verschueren et al., 2011). Additionally, batteries can defer grid reinforcement costs for up to 15% of transformer stations facing the highest specific grid reinforcement expenses (Gupta et al., 2021). Combining solar with batteries and Stirling engine cogeneration further enhances self-sufficiency and reduces grid variability by up to 40% in certain scenarios (Balcombe et al., 2015). Moreover, Electric Vehicles (EVs) offer flexibility services that benefit distribution grids and reduce the need for reinforcement (Knezović et al., 2015). Studies have explored frameworks leveraging EV-driven flexibility at the distribution level, demonstrating their capability to balance distributed generation and modulate consumption (Venegas et al., 2021; Knezović et al., 2015; Khederzadeh, 2016). Integrating EVs into electricity grids as flexibility providers has shown promising technical and economic viability, supported by advancements in technical solutions and local flexibility mechanisms (Gonzalez et al., 2019). Residential and office charging sites are identified as optimal for load reduction, particularly during peak charging hours (Rauma et al., 2021). Controlled charging strategies, even without discharging or reserve provision capabilities, contribute to overall system cost reduction and mitigate wind curtailment (Pavić et al., 2015). Additionally, demand response services in both residential and industrial sectors effectively manage distributed energy resources and electrical appliances, enhancing grid flexibility and optimizing production costs (Bode et al., 2017; Santecchia et al., 2022).

The literature reveals a clear pattern regarding the trade-off between capital expenditure (Capex) and flexibility (Flex) solutions, highlighting how distributed resources can defer network expansion. Initial research in this area focuses on formal market and planning frameworks; for instance, Poudineh and Jamasb (2014) proposes a contract for deferral scheme whereby DSOs—often legally restricted from asset ownership—remunerate private storage operators to manage congestion. Similarly, Spiliotis et al. (2016) and Asensio et al. (2017) utilize optimization models to demonstrate how demand-side flexibility, through bidding or bi-level programming, can substitute for physical reinforcement. Other contributions assess the techno-economic indicators and regulatory policy needed to ensure these resources are cost-effective; Resch et al. (2021) and Klyapovskiy et al. (2019) evaluate hosting capacity gains from storage, while Neetzow et al. (2019) and Nouicer et al. (2023) advocate for tariff redesigns and mandatory curtailment to align behavior with system needs. More recently, de Bazelaire et al. (2024) demonstrates that the viability of storage as a grid substitute is highly sensitive to marginal generation costs and reinforcement expenses. As opposed to these works, which treat flexibility as a controllable instrument managed through top-down contracts or intentional dispatch, our analysis accounts for the bottom-up technical reality of residential PV: the automatic, safety-driven disconnection of inverters due to over-voltage. This is a critical distinction, as DSOs often lack the legal authority to curtail residential injection intentionally (Mateo et al., 2017); instead, the system suffers from an uncoordinated physical response. While the aforementioned studies view curtailment as a deliberate tool for optimal grid sizing, our paper conceptualizes this disconnection risk as a congestion externality between prosumer households.

Compared to the existing literature that focuses on optimal planning, our approach identifies a systemic market failure: the misalignment between private and social costs leads to an under-provision of Flex and an excessive, inefficient reliance on Capex as a residual adjustment mechanism. By modeling disconnection probability as endogenous to total injection, we address a research gap regarding the transformation of a technical safety mechanism into a measurable economic inefficiency, allowing us to develop targeted instruments aimed at optimizing this trade-off.

The challenges associated with integrating solar panels into the existing grid are not unique. Similar issues have arisen with the introduction of new technologies, such as Electric Vehicles (EVs). EVs, especially fast chargers drawing up to 150 kW from the grid (Metais et al., 2022), stress distribution systems, particularly in clustered hubs. Their impact varies with driving patterns, charge characteristics, and penetration rates (Green II et al., 2011). Unlike Photovoltaic (PV) systems, which strain grids, EVs offer grid stability potential through smart integration strategies (Rahman et al., 2022). For instance, managing EV charging loads via smart grids can offset DPU surplus, enhancing grid stability without extensive reinforcement.

3. Model

3.1. The energy system

We consider a simplified energy system with two prosumers[3] indexed by $i = 1, 2$ and m traditional consumers, indexed by $j = 1, \dots, m$. All the consumers are living in the same neighborhood and are connected to the low-voltage grid. The grid is managed by a regulated Distribution System Operator (DSO), denoted as D. Consumers and prosumers use the grid to make exchanges with an electricity retailer R.

Each consumer j or prosumer i has a total consumption of electricity denoted by q_j or q_i expressed in MWh and they derive a surplus S_j, S_i from their electricity consumption. Prosumers are equipped with a decentralized production unit (DPU), typically solar panels. The DPU

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[3] The case of two agents is chosen to simplify the analysis, that can be easily extended to a given number of agents.

potentially produces y_i MWh of electricity at a unit cost of z per MWh. We suppose that $y_i \leq q_i$.[4]

We denote by $Y = y_i + y_2$ the total potential production of the prosumers, by $Q = q_1 + q_2$ their total consumption, and by $Q^T = Q + \sum_{j=1}^{m} q_j$ the total consumption.

A prosumer is making two types of exchanges with the retailer. When its production is insufficient to cover its consumption, the prosumer buys the difference from the retailer. We refer to this as "import" of electricity. Conversely, when its production exceeds its consumption, the surplus is sold to R and we refer to this as "export" of electricity. Finally, part of the electricity produced by the DPU is directly self-consumed by the prosumer.

We denote the export by x_i and the self-consumption by h_i. We have that $y_i = h_i + x_i$ and the imports are equal to $q_i - h_i$. We use $X = x_1 + x_2$ to denote the total exports.

The Distribution System Operator (DSO) plays a critical role in managing and maintaining the distribution network's operational integrity. The DSO incurs variable costs θ^m and θ^x for handling imports and exports, respectively, along with a fixed operational cost F. The DSO applies variable tariffs ρ^m and ρ^x for imports and exports, supplemented by a fixed fee ψ. The DSO is regulated and the network fees should cover the total costs of D.

The retailer R operates centralized production units that produce at a cost c per MWh. R sells electricity to prosumers and to the other m consumers at price p^m. In addition, R buys the production surplus from prosumers at price p^x. We take the convention that the variable grid fees ρ^m and ρ^x are included in the prices p^m and p^x and paid by R to D.

3.2. Capex and flex investments

3.2.1. Disconnection of the inverters

Massive electricity injection on the low voltage grid can cause overvoltage and lead, ultimately, to the disconnection of the inverters, in which case, the DPU no longer produces. In our model, we suppose that the DPU of prosumer i produces with probability Φ_i and does not produce with probability $(1 - \Phi_i)$. This means that the expected production of prosumer i is equal to $\Phi_i y_i$.

In the sequel, we will refer to Φ_i as the *probability of production* or, equivalently, to $(1 - \Phi_i)$ as the *probability of disconnection*. This probability depends on two key factors, the maximum load limit L of the line, and the power injections on the line made by the prosumers, as massive power injections are the main cause of over-voltages. For this reason, Φ_i will depend on the *total* exports of the prosumers (X) on the low voltage line. This implies that prosumers exert an externality on each other. If prosumer i exports more, it increases the probability of disconnecting both prosumers.

3.2.2. Capex investment by the DSO

There are two possibilities to increase the probabilities Φ_i. The first is to invest in the expansion and the reinforcement of the network to increase the load limit L. This investment, that we refer to as Capex, should be done by the DSO and we denote it by k. The cost of Capex investment k to the DSO is given by $C_c(k)$, where the cost function $C_c(\cdot)$ is assumed to be increasing and convex, reflecting rising marginal costs of infrastructure upgrades. This specification captures the fact that while initial improvements may be relatively cost-effective, more extensive expansions become increasingly expensive.

3.2.3. Flex investment by prosumers

The second possibility to increase Φ_i is that prosumers invest in Flex solutions. Flexibility consists in displacing the load from critical periods, where solar production is important and injections are massive, to other, less congested, periods. Flex solutions include load shifting and storage. We denote the Flex efforts of i by f_i. We suppose that an investment f_i costs $C_f(f_i)$ to prosumer i with $C_f(.)$ increasing and convex.

When a prosumer invests in flexibility, it will increase its self-consumption reducing both imports and exports. We will assume that:

Assumption 1. (1) $\frac{\partial x_i}{\partial f_i} = -\frac{\partial h_i}{\partial f_i} \leq 0$ and (2) $\frac{\partial^2 h_i}{\partial f_i^2} \leq 0$.

If we consider that the Flex investment is a residential battery, it means that a battery of capacity f that cost $C_f(f)$ can increase the prosumer's self-consumption by $h(f)$, with $h(.)$ increasing and concave.

3.2.4. The probability of production

Based on that, we express the probability Φ_i as $\Phi_i(X, k)$ and we make the following assumptions:

Assumption 2. (1) Φ_i is increasing and concave in k : $\Phi'_k := \frac{\partial \Phi_i}{\partial k} \geq 0$ and $\Phi''_k := \frac{\partial^2 \Phi_i}{\partial k^2} \leq 0$.

(2) Φ_i is decreasing and concave in X: $\Phi'_X := \frac{\partial \Phi_i}{\partial X} \leq 0$ and $\Phi''_X := \frac{\partial^2 \Phi_i}{\partial X^2} \leq 0$.

(3) $\Phi''_{X,k} := \frac{\partial^2 \Phi_i}{\partial X\ \partial k} \geq 0$.

Parts (1) and (2) are standard concavity assumptions, Capex and Flex investments have a decreasing impact at the margin on the probability of production. Part (3) means that, at the margin, Capex investments alleviates the depressing effect of exports. In that sense Capex and exports are (stochastic) complements with respect to the probability of production. Increasing the amount of one type of investment decreases the amount of the other one, then Capex and Flex are substitutes.

A consequence of Assumptions 1 and 2 is that the Φ_i is increasing and concave in f_i. Flex investments help to reduce the occurrence of disconnection:

$$\Phi'_{f_i} \ := \ \frac{d\Phi_i(X,k)}{df_i} = \Phi'_X \frac{\partial x_i}{\partial f_i} \geq 0,$$

$$\frac{d^2\Phi_i(X,k)}{df_i^2} = \Phi''_X \left(\frac{\partial x_i}{\partial f_i}\right)^2 + \Phi'_X \frac{\partial^2 x_i}{\partial f_i^2} \leq 0.$$

Note that if $\frac{\partial x_i}{\partial f_i} < 0$, the prosumer has, on top of a higher probability of production, an additional benefit from the Flex investment. If 1 MWh of his production is self-consumed rather than exported, the prosumer has a benefit of $p^m - p^x$ i.e. instead of receiving the export price p^x from R, it saves on the import price p^m. So the Flex investment has both a direct effect, as it increases Φ_i and an indirect benefit as it replaces export by self-consumption.

In order to encompass the limit situation in which flexibility measures have only a direct impact on the probability of production without limiting exports (corresponding to the case where $\frac{\partial x_i}{\partial f_i} = 0$)[5] let us assume that[6]:

$$\lim_{\frac{\partial x_i}{\partial f_i} \to 0} \Phi'_{f_i} > 0.$$

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[4] Production and consumption take place in continuous time, but in our model, we focus only on aggregate values over a relevant period. In the extensions, we explore some dynamic aspects of this model.

[5] This would be the case when Flex measures displace load at critical periods where the probability of disconnection is the highest to periods where there is less pressure on the grid, thereby increasing Φ, but without impacting the total volume of export.

[6] At the cost of unnecessary complexity, an alternative assumption would be to define $\Phi(X, k, f)$ with $\frac{\partial \Phi}{\partial f} > 0$.

3.3. Payoff functions

We have all the elements to define the objective function of each agent in the economy. Omitting arguments for the function Φ, the utility of a prosumer (U_i) and a consumer (U_j) are:

$$U_i = S_i - p^m q_i + \Phi_i p^m y_i - \Phi_i (p^m - p^x) x_i - z y_i - C_f(f_i) - \psi, \tag{1}$$

$$U_j = S_j - p^m q_j - \psi. \tag{2}$$

The retailer's profit is

$$\pi^R = (p^m - \rho^m - c)(Q^T - \sum_{i=1,2} \Phi_i y_i) + (p^m - p^x - \rho^x) \sum_{i=1,2} \Phi_i x_i. \tag{3}$$

The DSO's profit is

$$\pi^D = (\rho^m - \theta^m)(Q^T - \sum_{i=1,2} \Phi_i y_i) + (\rho^x - \theta^x) \sum_{i=1,2} \Phi_i x_i - C_c(k) - F + (2+m)\psi. \tag{4}$$

In our model, the only choice variables are Capex k and Flex f_i. We will further assume that the two prosumers are identical, with the same production $y_1 = y_2$ and self-consumption $h_1 = h_2$, implying the same level of exports $x_1 = x_2$. We further assume that they face an identical probability of production: $\Phi_i = \Phi(X, k)$.

3.4. Grid tariffs and energy prices

We define two benchmark configurations, for the grid tariff and for the energy prices.

A *Coasian tariff* is a two-part tariff where the fixed part is set to the fixed cost and the variable parts are set to the variable costs:

$$(\rho^m; \rho^x) = (\theta^m; \theta^x) \quad \text{and} \quad \psi = \frac{F + C_c(k)}{2 + m}. \tag{5}$$

A *competitive market* is a market where the energy prices are set to marginal cost:

$$p^m = c + \rho^m \qquad \text{and} \quad p^m - p^x = \rho^x. \tag{6}$$

3.5. The value of decentralized production

For our analysis, it is useful to identify the value of the decentralized production Y and we distinguish a social ($\bar{v}$) and a market value ($\hat{v}$). Both values are expressed as a monetary value per MWh.

$$\bar{v} = c + \theta^m - \theta^x \frac{X}{Y}, \tag{7}$$

$$\hat{v} = p^m - (p^m - p^x)\frac{X}{Y}. \tag{8}$$

One MWh of decentralized production replaces one MWh produced by the retailer, implying a cost saving of $c + \theta^m$ but a fraction $\frac{X}{Y}$ is injected into the grid (export) implying an extra grid cost θ^x. For the market value, we evaluate the savings and the injection at their respective market prices. With a Coasian tariff and competitive prices, the two values coincide: $\bar{v} = \hat{v}$. As the total decentralized production is Y, its social and market values are $\bar{v}Y$ and $\hat{v}Y$, respectively.

In the sequel, we will assume that the decentralized production has a positive social value: $\bar{v} > 0$. If this assumption is not satisfied, our problem has a simple solution as it is optimal to curtail the DPU and therefore, there is no need to invest in Capex or in Flex. A negative social value results from costly injections on the grid (a high θ^x) combined with a low self-consumption ratio (a high $\frac{X}{Y}$). A low cost c for the centralized production may also contribute to a negative value for $\bar{v}$.[7]

4. Capex and flex investment decisions

In this section, we derive the optimal Capex and Flex investments in a first-best benchmark and in a decentralized market outcome.

4.1. First-best decisions

The social planner maximizes the society's welfare function, which is the sum of net surpluses and profits of all agents in the economy: $W = \sum_i U_i + \sum_j U_j + \pi^D + \pi^R$,

$$W = S - (\theta^m + c)(Q^T - \Phi Y) - \Phi\theta^x X - zY - 2C_f - C_c - F, \tag{9}$$

where S is the total surplus of consumers and prosumers: $S = \sum_i S_i + \sum_j S_j$.

From a welfare point of view, increasing the investment in Capex ($l = k$) and in Flex ($l = f$) has both a benefit and a cost, and welfare maximization equalizes the benefits and costs at the margin. The marginal benefit is the additional decentralized production available for the system amounting to $\Phi'_l Y$, and this additional production has a unit value equal to $\bar{v}$. The marginal cost is the investment cost C'_l. In addition, the marginal cost of Flex is reduced by the benefit of increased self-consumption and the corresponding reduction in exports, leading to a lower cost for the network. In other words, for the system, the adjusted marginal cost of Flex is $C'_f + \Phi\theta^x \frac{\partial x_i}{\partial f}$ which is below C'_f as $\frac{\partial x_i}{\partial f} < 0$.

We characterize the first-best investments in the following Lemma and we provide the detailed computation in the appendix.

Lemma 1. *When $\bar{v} > 0$, Capex k^* and Flex f^* optimal levels are such that:*

$$\frac{\Phi'_k}{\Phi'_f} = \frac{C'_c}{C'_f + \Phi\theta^x \frac{\partial x_i}{\partial f}}, \tag{10}$$

and k^* and f^* increase with $\bar{v}$ and Y.

The ratio Φ'_k / Φ'_f represents the marginal rate of (stochastic) substitution (MRS) between Capex and Flex decisions. It is the rate at which the society can replace some amount of Capex investments in order to increase Flex investments while maintaining the same probability of production for prosumers. At the first best optimum, this MRS between f and k is proportional to the ratio of their respective adjusted marginal costs.

4.2. Decentralized outcomes

Consider now the decentralized outcome, where each prosumer chooses its flex investment f_i and the DSO chooses k. We suppose that prosumers maximize their utility U_i and that the regulated DSO chooses k in order to maximize W. The grid tariffs are set by the regulator to guarantee that $\pi^D = 0$.

The structure of the problem is similar to the first best, with two main differences. First, prosumers value decentralized production at the market value $\hat{v}$ and not at the social value. Second, for prosumer i, the marginal benefit of flex is the additional decentralized production at his place $\Phi'_f y_i \hat{v} = \Phi'_f \frac{Y}{2} \hat{v}$ and he does not take into account that his flex investment also benefits prosumer j.

We characterize the decentralized investments in the following Lemma and we provide the detailed computation in the appendix.

Lemma 2. *When $\bar{v}, \hat{v} > 0$, Capex $\hat{k}$ and Flex $\hat{f}$ decentralized levels are such that:*

$$\frac{\Phi'_k}{\Phi'_f} = \frac{C'_c}{C'_f + \Phi(p^m - p^x)\frac{\partial x_i}{\partial f}} \frac{\hat{v}}{2\bar{v}}, \tag{11}$$

and $\hat{k}$ increases with $\bar{v}$ and Y; $\hat{f}$ increases with $\hat{v}$ and Y.

For the decentralized outcome, the MRS is now equal to a product of two ratios. The first is the market-valued version of the ratio of adjusted marginal costs, seen above. The second captures the difference between market and social value of decentralized production. For the system,

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[7] We will discuss this case further in Section 6.2.

decentralized production has a value $\bar{v}$, for the prosumer, the value is $\frac{\hat{v}}{2}$. This difference in valuation affects the amount of investment.

To illustrate, with Coasian tariffs and competitive prices ($\bar{v} = \hat{v}$), the decentralized outcome is given by:

$$\frac{\Phi'_k}{\Phi'_f} = \frac{1}{2}\frac{C'_c}{C'_f + \Phi\theta^x \frac{\partial x_i}{\partial f}} < \frac{C'_c}{C'_f + \Phi\theta^x \frac{\partial x_i}{\partial f}}, \tag{12}$$

and prosumers invest less in Flex compared to the first best.

Proposition 1. *With Coasian network tariffs and competitive energy markets, the first best cannot be achieved and the Flex investment $\hat{f}$ is lower than f^*.*

A lower investment by the prosumers has two consequences on the DSO incentives to invest in Capex. First, at the margin, the Capex investment becomes more productive as $\Phi''_{Xk} \geq 0$, thereby increasing the incentives to invest. Second, as the available decentralized production is lower (since Φ decreases), the DSO has less incentives to invest in Capex. Depending on which effect dominates the other, we have more or less Capex investment by the DSO. We identify in the next result the conditions for a higher (or lower) Capex investment.

Corollary 1. *With Coasian network tariffs and competitive energy markets, if $W''_{k,f} < 0$ then $\hat{k} > k^*$ and, if $W''_{k,f} > 0$ then $\hat{k} < k^*$.*

Even with fully cost reflective prices, prosumers do not capture all the benefits of their investment and they underinvest in Flex. As Flex and Capex are substitutes (Assumption 2), it increases the incentives to invest in Capex and, eventually, the grid may overinvest in Capex compared to the first best. But this is inefficient and costly. It would have been more efficient to have less investment by the DSO and more by the prosumers and we discuss in the sequel, the possible policies to restore the first best.

5. Internalizing congestion externalities

In this section, we discuss two instruments available to correct the externality problem and restore the first best.

5.1. Grid tariffs manipulation

One possible way to solve the externality problem is to distort the grid tariffs and depart from the Coasian scheme. Tariffs are powerful instruments in the hands of regulator since they are the only channel between production and consumption that can be manipulated to reach social optimum or achieve policy objectives.

Our objective is to find non-Coasian tariffs $(\rho^m;\rho^x;\psi) \neq (\theta^m;\theta^x;\frac{F+C_c(k^*)}{2+m})$ that would achieve the first best under a budget balance for the DSO.

For the first best, it means that the conditions defined in Eqs. (10) and (11) should coincide. The budget balance condition implies that π^D defined in Eq. (4) should be set equal to zero. Interestingly, the two problems could be dissociated: the variable part of the tariff should be set to induce the first best investment, the fixed part should be adapted to satisfy the budget constraint.

To implement the first best, the regulator should adapt the variable grid fees (ρ^m, ρ^x) to increase the Flex investment by prosumers. For that, it must make self-consumption more attractive. This can be done either by inflating the fee ρ^m, which in turn increase the price paid for importing electricity, or by decreasing the fee ρ^x paid for exporting electricity, which in turn decreases the price received for exports. In both case, the benefit of self-consumption increases and prosumers derive a higher private benefit from Flex.[8] Conditions (10) and (11) define an increasing linear locus $(\rho^m;\rho^x)$ that induces the prosumers to make the first best investment.

Proposition 2. *With non-Coasian tariffs and competitive prices, the first best Flex and Capex of investment can be achieved if (ρ^m, ρ^x) lie in the locus Λ defined as:*

$\Lambda := \{\rho^m, \rho^x\}$ *such that* $\rho^m + c = \mathcal{A}\rho^x + \mathcal{B}$,

where $\mathcal{A} > 0$ *and* $\mathcal{B} > 0$.

5.2. Flex subsidies

Suppose that the Flex investment (f) is a residential battery. A battery allows to store the excess solar production to consume it later, especially during peak hours. A battery therefore reduces exports and increases the prosumer's self-consumption.

To encourage individual battery adoption, the government can decide to subsidize privately owned batteries. Suppose that the government proposes a subsidy to a battery of capacity f that is equal to $s(f)$.[9] In this case, the prosumer chooses the flex investment f_i to maximize $U_i + s(f_i)$. The subsidy reduces the prosumer's adjusted marginal cost of the Flex investment by s'. In the next proposition, we show that if the subsidy is correctly designed, it is possible to restore the first best investment in Flex.

Proposition 3. *With Coasian tariffs and competitive prices, the first best Flex and Capex investments can be achieved with a subsidy scheme $s^*(f)$ satisfying*

$$\left(s^*\right)' = \Phi'_f \frac{\bar{v}Y}{2}.$$

This result is no surprising, in the presence of an externality, tax and subsidies are well-known instruments to internalize it. This is famously known as Pigouvian subsidy in economics and stipulates that, the subsidy must be equal to the aggregated net marginal benefit of the externality.

But providing subsidies to restore efficiency usually generates additional costs. If subsidies are paid by the DSO, this additional cost should be passed through to consumers, for instance by increasing the fixed fee. If instead they are paid out of the general budget, there are shadow costs of subsidies linked to the deadweight costs of taxation and to the management of the administrative process. The cost of these subsidies should be taken into account in the design of the optimal subsidies. Finally, with heterogeneous prosumers, subsidies might be location-specific and the first best cannot be restored with uniform subsidies. We discuss this point further in Section 6.1.

5.3. Comparisons of instruments and redistributive aspects

The two proposed instruments restore the optimality of investment but they are not equivalent. In general, subsidies are compatible with Coasian tariffs but they are associated with specific costs: costs of public funds and costs of uniform subsidies. On the other hand, distorted grid tariffs are usually associated with allocative inefficiencies. Hence, the optimal instrument depends on an arbitrage between these dimensions.

In our model, consumption levels are supposed to be given. Hence, distorting the grid tariff does not impact consumption.[10] For this reason, Flex subsidies and distorted tariffs both restore the first best and yield the same welfare level, up to the shadow cost of public funds. They are also built up to achieve break-even for the DSO and, with competitive

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[8] Similarly, if the energy retailer has market power, it can charge a higher retail price p^m to consumers and buy the solar surplus at a lower price p^x. This would make self-consumption more profitable and boost investment in Flex.

[9] Our formulation allows for both a linear subsidy (constant per kWh of battery capacity) and a non-linear one.

[10] The electricity consumption has a low elasticity, so this effect is in principle limited.

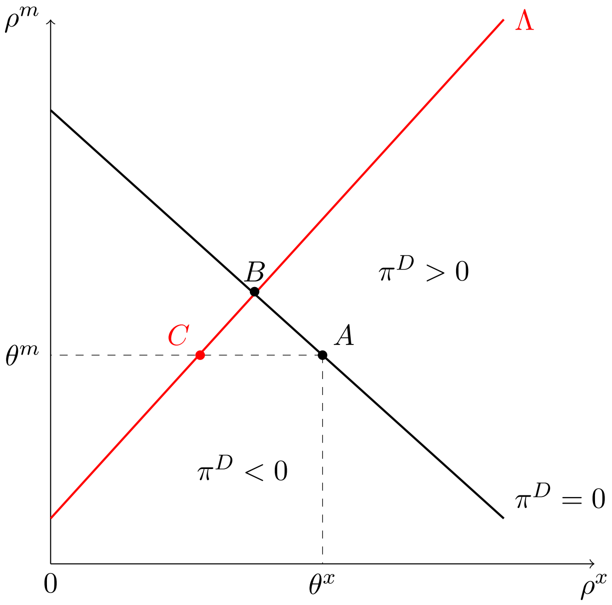

Fig. 1. First best tariff (Λ) and zero-profit line ($\pi^D = 0$). Point A corresponds to the Coasian tariff.

prices, retailer's profits are zero. Hence, these two instruments only have an impact on the prosumers' and the consumers' surpluses.

To discuss these redistributive aspects, we represent on Fig. 1, the locus Λ of grid tariffs (ρ^m, ρ^x) that implement the first best identified in Proposition 2. The Coasian tariff $(\rho^m, \rho^x) = (\theta^m, \theta^x)$, represented by point A on the figure, does not belong to this locus (Proposition 1) unless appropriate subsidies are paid to prosumers (Proposition 3).

On Fig. 1, we also represent a zero-profit line ($\pi^D = 0$) which is the combination of grid tariffs such that, keeping the fixed fee constant and equal to the Coasian case ($\psi = \frac{F+C_c(k^*)}{2+m}$), the DSO satisfies the budget balance condition. To the left of this zero-profit line, we have $\pi^D < 0$ and the regulator must increase the fixed fee to satisfy the constraint $\pi^D = 0$. On the contrary, to the right of this line, $\pi^D > 0$ and the regulator can decrease the fixed fee.

To discuss the redistributive aspects we will consider three points on the figure: A, B and C. Coasian tariffs correspond to point A, points B and C implement the first best, leaving unchanged the fixed fee (B) or the import fee (C).

If we compare A and C, for consumers, their volumetric part of the bill is unchanged, but $\pi^D < 0$ and the fixed fee must increase to satisfy the DSO budget constraint. If we compare A and B, the fixed fee is at the Coasian level, but the volumetric part increases. In both cases, consumers end up paying more and there is a net transfer from consumers to prosumers. But their preferred option depends on their relative consumption level. Consumers with low q_j prefer B while those with high q_j prefer C, showing that consumers are unequally impacted by the tariff distortions. Whether consumers prefer Flex subsidies instead of distorted tariffs depends on the relative importance of the tariff surcharge relative to the cost of subsidies and how subsidies are financed, which is out of the scope of this paper.

When the regulator solves the externality problem exerted by prosumers on each other, it possibly hurts the other consumers i.e. prosumers exert a negative externality on traditional consumers. Hence, providing adequate incentives to prosumers (and to the grid) has important redistributive aspects as Fig. 1 illustrates.

6. Extensions

We extend the baseline model along three dimensions. First, we introduce heterogeneity among prosumers, particularly with respect to their location on the distribution network and its implications for disconnection risk and policy design. Second, we incorporate temporal dynamics, allowing for time-varying grid conditions and flexibility needs. Third, we endogenize prosumer investment in distributed production units and examine the resulting inefficiencies.

6.1. *Heterogeneous prosumers*

In practice, prosumers are heterogeneous, particularly in their physical location within the distribution network. This spatial heterogeneity has meaningful implications for both the physical impact of DPU and each agent's exposure to disconnection risk under conditions of grid congestion. Empirical studies (e.g., Navarro et al., 2013; Saad et al., 2018; Tursun et al., 2013) show that PV systems situated closer to the distribution transformer typically exert stronger voltage impacts, whereas prosumers located further downstream are more likely to experience curtailment or disconnection. As a result, locational factors shape the size and direction of the externalities each agent imposes or faces.

Formally, this spatial heterogeneity implies that the probability of disconnection is not uniform across agents: $\Phi_i \neq \Phi_j$. In the symmetric case of the baseline model, we showed that a uniform flexibility subsidy $s^*(f)$ can replicate the first-best allocation by internalizing the marginal external benefit associated with Flex investments. However, under spatial heterogeneity, the marginal external value of Flex differs across prosumers. In particular, the negative externality arises only from the actions of the agent who remains connected during grid stress. By exporting power during congestion, this agent imposes an external cost on the other through increased disconnection risk. In contrast, the disconnected agent imposes no such externality and already behaves optimally from a social optimum perspective. The externality, therefore, becomes one-sided[11] and we have $\Phi_1 = 1$ and $\Phi_2 = \Phi(X, k)$ where the latter is defined above.

In this setting, the optimal policy is inherently asymmetric. Only prosumer 1 whose injection potentially causes harm to the other prosumer 2 should receive a subsidy to incentivize Flex investment. Specifically, the disconnected prosumer does not require any subsidy, while the connected prosumer should be compensated through a positive Flex subsidy, such that,

$$s_f^1 = s^*(f) > 0 \quad \text{and} \quad s_f^2 = 0$$

This policy structure ensures that private incentives align with the socially optimal allocation of flexibility. Subsidizing the disconnected agent would be wasteful, as their investment decision does not influence the equilibrium outcome during congestion.

Despite the theoretical appeal of asymmetric subsidies, their implementation is challenging in practice. Differentiating incentives based on real-time locational effects requires granular monitoring of grid conditions and sophisticated administrative systems. Moreover, the marginal value of Flex depends not only on static location but also on evolving grid states, further complicating policy design. As a result, regulators often resort to uniform instruments, that is an identical subsidy scheme that applies to all prosumers. We now show that there is a cost associated with uniform subsidies.

In the appendix, we solve the model with $\Phi_1 = 1$ and $\Phi_2 = \Phi(X, k)$ to show the following. First, we show that it is not possible to replicate the first best with uniform subsidies. A uniform Flex subsidy improves outcomes relative to the unregulated equilibrium, but it does not replicate the first-best allocation. One prosumer overinvests in Flex, while the other underinvests.

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[11] In an environment with multiple prosumers, the externality will be inherently asymmetric but not necessarily one-sided.

Proposition 4. *With heterogeneous prosumers and a uniform subsidy scheme, it is not possible to replicate the first best. Furthermore if* $\hat{f}_1 = f_1^*$ *then* $\hat{f}_2 > f_2^*$ *and if* $\hat{f}_2 = f_2^*$ *then* $\hat{f}_1 < f_1^*$.

Second, we show that the optimal Flex investment depends on the repartition of investment between the two prosumers. This means that it is not a total storage capacity that is needed but it should be correctly allocated among prosumers.

Corollary 2. *With heterogeneous prosumers and a uniform subsidy scheme, it is possible to replicate the first total storage capacity* $\hat{f}_1 + \hat{f}_2 = f_1^* + f_2^*$ *but* $W(\hat{f}_1, \hat{f}_2) < W(f_1^*, f_2^*)$.

The inability to correctly internalize heterogeneity in external effects leads to an inefficient investment mix, even in the presence of corrective instruments. The resulting inefficiency necessitates greater reliance on capital expenditure (Capex) to accommodate DPU. In sum, spatial heterogeneity in prosumer behavior and disconnection risk limits the effectiveness of uniform subsidies. Without the ability to tailor policy instruments to local network impacts, flexibility remains undervalued, and the system must compensate through more extensive and costly infrastructure upgrades.

6.2. Temporal dynamics and time-varying incentives

The baseline model abstracts from variation over time, assuming static congestion and Flex requirements. In practice, however, grid conditions vary significantly across time scales within the day, across seasons, and in response to weather and consumption patterns. Solar generation typically peaks around midday, while residential demand rises in the morning and evening. These temporal mismatches between generation and load create recurring congestion and disconnection risks.

To incorporate this temporal structure, we index time by $t \in \mathcal{T}$, where $\mathcal{T}$ represents a relevant time horizon, for example a typical day or year. Each prosumer's net injection, $x_{i,t} = y_{i,t} - q_{i,t}$, varies with solar production and consumption at each moment in time. Consequently, the probability of not being disconnected becomes time-dependent: $\Phi_t = \Phi(X_t, k)$, where $X_t = \sum_i x_{i,t}$ is the aggregate injection at time t, and k denotes Capex, which is assumed fixed over time. While Capex is static, Flex investments allow prosumers to alter their injection profiles dynamically, thereby influencing the shape of X_t and the evolution of Φ_t. Hence, the planner should not only incentivize for the correct amount of Flex investment but also for the correct timing for using flexibility measures by the prosumers. For a battery, it means that there is an optimal capacity for the battery but also an optimal timing for charging/discharging it.

So, the first best consists in specifying a battery capacity (f_i) for prosumer i and a charging path (ζ_{it}), where ζ_{it} refers to the amount of electricity (in kWh) that is charged ($\zeta_{it} > 0$) or discharged ($\zeta_{it} < 0$) at period t. In this formulation $x_{it} = \max[y_{it} - q_{it} - \zeta_{it}, 0]$. The planner should maximize the welfare for f_i, ζ_{it} and k.

The corresponding decentralized outcome will be inefficient. Prosumers do not internalize the externality and choose a level f_i that is too low. In addition, their incentives to charge and discharge the battery may not be aligned with the first-best, and the decentralized charging path is unlikely to coincide with the first best. For instance, prosumers may want to charge their battery when they have production surplus while the first best would call for charging the battery when there is tension on the line.

To align the interest of the prosumers with the first best, the regulator should use two instruments: a subsidy to make the prosumer's choice closer to the optimal capacity and time-varying export tariffs to induce a charging path close to the optimal one. Making ρ_t^x time-dependent enhances the instrument's precision by penalizing injections when the grid is most congested. For instance, increasing export tariffs during midday solar peaks discourages uncoordinated injections and incentivizes self-consumption or storage.[12] Conversely, during morning and evening consumption peaks, lower export tariffs or adjustments to ρ_t^m, can promote grid imports or storage discharge, alleviating system stress.

Implementing these dynamic grid tariffs requires supporting infrastructure, including smart metering, automated controls, and digital platforms for price communication and response coordination. Despite these challenges, the potential gains from moving away from static pricing could be substantial. The analysis underscores the central result that, in the presence of time-varying grid constraints, static incentives lead to inefficient patterns of investment and behavior. Efficient integration of DPU thus necessitates dynamic policy instruments that reflect temporal variation in externalities.

Finally, in a dynamic setting, the cost of production by the retailer could also be time dependent: c_t, with an impact on the social value of the decentralized production who becomes $\bar{v}_t$. In many markets, we observe that the price of electricity decreases when solar production is abundant, depressing $\bar{v}_t$ who may eventually become negative during some periods t. Hence, using Lemma 1, one may conclude that a lower cost c_t would decrease the investment.

However, during solar peaks, if the social value of the decentralized production is likely to be lower, the level of decentralized production is likely to be large i.e. $\bar{v}_t$ may be negatively correlated with $Y_t = \sum_i y_{i,t}$. In the dynamic setting, the investments in $l = k, f$ will be driven by the marginal benefit of increasing decentralized production which is equal to $\sum_t (\Phi'_l)_t \bar{v}_t Y_t$. Hence, a lower cost for the solar energy does not automatically means that the optimal Capex and Flex investments decrease.

6.3. Endogenous DPU investment

In the baseline framework, prosumer investment in distributed production capacity is treated as exogenous. In practice, however, prosumers choose how much capacity to install, balancing expected cost savings, regulatory incentives, and technical constraints. These investment decisions directly influence system-wide outcomes by shaping net injections and congestion patterns.

Let y_i denote the installed generation capacity of prosumer i. An increase in y_i raises expected exports, subject to the extent that self-consumption can offset generation. Under the reasonable assumption that self-consumption smoothing is incomplete, we have $\partial x_i / \partial y_i = 1 - \partial h / \partial y_i \geq 0$, implying that a larger DPU leads to greater net injection. Consequently, this also implies a negative effect on the probability of grid connection through $\Phi'_{y_i} := \frac{\partial \Phi(X,k)}{\partial y_i} = \Phi'_X \cdot \frac{\partial x_i}{\partial y_i} \leq 0$. As each agent acts atomistically, they do not internalize the negative effect of their capacity expansion on others' disconnection risk, which leads to oversizing of DPU.

This yields a further source of inefficiency in the decentralized equilibrium. Relative to the socially optimal level of generation y^*, prosumers overinvest in DPU capacity: $\hat{y} > y^*$. This overinvestment exacerbates grid congestion and increases the probability of disconnection. Combined with the underinvestment in Flex identified earlier, the system becomes overly reliant on expensive and time-intensive infrastructure upgrades (Capex) to accommodate the same level of hosting capacity and to maintain reliability.

From a regulatory perspective, this distortion highlights the importance of re-evaluating current incentive structures. Many existing schemes, such as net metering or installation subsidies, disproportionately reward DPU expansion while neglecting the associated externalities. A more efficient approach would involve reducing the marginal

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[12] Market prices are also varying during the days and prices are low (eventually negative) during solar periods when production is large. If the price p^x paid to prosumers is time-varying and following market prices, this will also incentivize prosumers to self-consume.

return to injection during peak congestion periods, increasing the return to Flex, and incorporating locational or capacity-based restrictions to align individual investment decisions with system-wide constraints. Such adjustments would reduce the need for extensive network reinforcement and foster a more balanced and resilient distributed energy system.

7. Discussion and conclusion

The increasing deployment of decentralized production units (DPUs), notably rooftop photovoltaics, has introduced new externalities in the operation of distribution grids. A primary concern is the emergence of over-voltage conditions due to high local injection, which can trigger disconnection of prosumers. This disconnection risk is endogenous to network conditions and constitutes a negative externality: individual injections raise the probability of others being disconnected, distorting decentralized incentives and undermining allocative efficiency.

To analyze this, we construct an agent-based framework featuring prosumers, traditional consumers, a distribution system operator (DSO), and a retailer. Within this setting, we solve analytically for the optimal allocation under both decentralized and coordinated regimes. Our analysis focuses on the trade-off between capital expenditure (Capex) for grid reinforcement and investment in flexibility (Flex), such as battery storage or responsive demand, which can help manage local congestion.

The key result is that the decentralized equilibrium is systematically inefficient: it is characterized by under-provision of Flex, and excessive reliance on Capex. The root of this inefficiency lies in the misalignment between private and social costs. Prosumers do not internalize the congestion externality they impose, and Flex resources, despite generating positive local spillovers, are not sufficiently rewarded in the market outcome. Capex, although effective in maintaining grid reliability, becomes the residual adjustment mechanism, possibly leading to overcapitalization of the grid. We evaluate a set of corrective instruments, including grid tariff reforms and Flex subsidies. While such tools can partially bridge the gap between decentralized and optimal outcomes, their efficacy is limited by asymmetric information and heterogeneity across prosumers. In particular, uniform Flex subsidies fail to reflect spatial differences in disconnection risk and marginal system value of flexibility.

Our extensions further underscore the challenges of managing decentralized integration under informational and institutional constraints. First, introducing heterogeneity in prosumer location reveals that disconnection risk, and thus the marginal externality of flexibility, is uneven across agents. Prosumers situated closer to transformers may exert stronger grid impacts and face lower curtailment risk, while those further downstream are more vulnerable and respond differently to incentives. This spatial asymmetry limits the effectiveness of uniform Flex subsidies, which tend to overcompensate some agents while under-incentivizing others, leading to an inefficient allocation of resources. Second, incorporating temporal dynamics shows that congestion and the value of flexibility are highly time-dependent. Static policy instruments, such as flat subsidies or uniform export tariffs, fail to target critical periods of grid stress, typically midday during solar peaks, thereby weakening incentives for prosumers to shift injections when it matters most. Third, when DPU sizing is endogenized, a new externality arises: prosumers have incentives to oversize generation capacity without accounting for the increased congestion they impose. This exacerbates disconnection risk and inflates the need for Capex investments. Together, these extensions reveal that overbuilt DPUs and underprovided Flex reinforce each other, intensifying the system's dependence on costly infrastructure upgrades.

The policy implications are clear: more sophisticated, differentiated instruments are necessary to internalize the full spectrum of spatial and temporal externalities. Time-varying export tariffs that penalize injections during solar peaks can align private behavior with system conditions, improving the allocative efficiency of Flex. Spatially differentiated Flex remuneration or local caps on DPU investment can better reflect network constraints. In turn, conditioning subsidies or support schemes on hosting capacity can curb the incentive to oversize generation assets. But, as we have shown, solving the congestion externality has important redistributive impacts, and non-prosuming consumers may be negatively impacted by the solution chosen. Taking these redistributive impacts into consideration is key for a well-designed policy.

Finally, while this study relies on an analytical characterization of equilibrium outcomes, future research should move toward simulation-based models calibrated to empirical grid data. Incorporating agent-level heterogeneity, stochastic demand and generation, and realistic network constraints would allow for testing the robustness of the proposed mechanisms in more complex settings. Such simulations could validate key theoretical insights in larger systems and inform policy under real-world variability. Additionally, future work could explore the operational role of aggregators, programmable contracts, and digital infrastructure, which may enable the deployment of more sophisticated, targeted policy instruments in practice.

In sum, the transition toward decentralized energy systems necessitates a careful rethinking of market design and regulatory incentives. Ensuring efficiency and reliability in distribution networks will require tools that are spatially and temporally responsive, technologically neutral, and capable of addressing the incentive misalignments that arise in increasingly heterogeneous energy systems.

Several extensions would further enrich the analysis. First, moving from a static to a fully dynamic framework (beyond the extension we propose in Section 6.2) would allow the model to incorporate stochastic and intermittent solar generation, capturing uncertainty in irradiation and its interaction with demand over time. Such a setting would make it possible to study intertemporal investment and operational decisions, learning effects, and the option value of flexibility under uncertainty. Second, and moving beyond the heterogeneity configuration we are studying in Section 6.1, explicitly embedding the physical structure of the distribution grid by modeling nodal locations, line impedances, and voltage constraints would allow agents' actions to affect the network asymmetrically. This would sharpen the analysis of spatial externalities, as identical injections or withdrawals would have heterogeneous system impacts depending on location, thereby strengthening the case for location-specific pricing and incentives. Third, an important institutional extension would be to endogenize the role of the DSO as a market designer by allowing it to organize a local flexibility market (see footnote 2). In such a market, consumers and prosumers could trade rights to withdraw from or inject power into the grid, subject to local network constraints. This mechanism could provide a decentralized yet coordinated way to internalize congestion externalities, reveal local scarcity values, and allocate flexibility efficiently without relying solely on administrative tariffs or subsidies. Exploring the efficiency, distributional consequences, and implementability of such local markets remains a promising direction for future work.

CRediT authorship contribution statement

Voahary Andriamaromanana: Writing – original draft, Validation, Methodology, Formal analysis, Conceptualization. **Axel Gautier:** Writing – original draft, Validation, Methodology, Formal analysis, Conceptualization. **Jean-Christophe Poudou:** Writing – original draft, Validation, Methodology, Formal analysis, Conceptualization.

Appendix

Proof of Lemma 1

Maximizing W with respect to both k, f_i leads to the following first order conditions for $i = 1, 2$, when $f_i = f$,

$$W'_k = 0 \Leftrightarrow \Phi'_k \underbrace{[(\theta^m + c)Y - \theta^x X]}_{\bar{v}Y} - C'_c = 0, \tag{A.1}$$

$$W'_f = 0 \Leftrightarrow \Phi'_X \frac{\partial x_i}{\partial f} \underbrace{[(\theta^m + c)Y - \theta^x X]}_{\bar{v}Y} - \Phi\theta^x \frac{\partial x_i}{\partial f} - C'_f = 0. \tag{A.2}$$

These conditions are sufficient as the hessian of W is definite negative due to our Assumptions. As $\Phi'_X \frac{\partial x_i}{\partial f} = \Phi'_f$, isolating Φ'_k and Φ'_f in these equations leads to Eq. (10). From the first order conditions, it is obvious that k^* and f^* increase with $\bar{v}$ and Y.

Finally if $\bar{v} < 0$, we have a corner solution and $k^* = f^* = 0$.

Proof of Lemma 2

The decentralized outcome is characterized by Eq. (A.1) and the following first order conditions, for $i = 1, 2$:

$$\frac{\partial U_i}{\partial f_i} = \Phi'_X \frac{\partial x_i}{\partial f_i} \underbrace{\left[p^m y_i - (p^m - p^x)x_i\right]}_{\hat{v}Y/2} - \Phi(p^m - p^x)\frac{\partial x_i}{\partial f_i} - C'_f = 0.$$

Then summing up both prosumers conditions $\frac{\partial U_1}{\partial f_1} + \frac{\partial U_2}{\partial f_2}$ leads to:

$$\Phi'_f \underbrace{\left[p^m Y - (p^m - p^x)X\right]}_{\hat{v}Y} = \Phi(p^m - p^x)\left(\frac{\partial x_1}{\partial f_1} + \frac{\partial x_2}{\partial f_2}\right) + 2C'_f. \tag{A.3}$$

By symmetry of prosumers we have $\frac{\partial x_1}{\partial f_1} + \frac{\partial x_2}{\partial f_2} = 2\frac{\partial x_i}{\partial f}$ and, when combined with condition (A.1) above, this leads to the market equilibrium condition (11) for any energy prices and grid tariffs.

Finally, if $\bar{v} < 0$, we have a corner solution and $\hat{k} = 0$ and, if $\hat{v} < 0$, $\hat{f} = 0$.

Proofs of Proposition 1 and Corollary 1

Consider Coasian tariffs and competitive energy prices. For any k, assume that $f = f^*$, then using (A.2) in (A.3) implies

$$\frac{\partial U_i}{\partial f} = -\frac{1}{2}\left(C'_f + \Phi\theta^x \frac{\partial x_i}{\partial f}\right) < 0.$$

By concavity of U_i in f_i, this leads to the result $\hat{f} < f^*$.

Moreover differentiating the DSO condition (11), with respect to f_i and applying Assumption 2 implies

$$W''_{k,f} = \frac{\partial x_i}{\partial f}\left(\Phi''_{X,k}\ \bar{v}Y - \Phi'_k\ \theta^x\right) \leq 0,$$

iff

$$\frac{\Phi''_{X,k}}{\Phi'_k} \geq \frac{\theta^x}{\bar{v}Y} \geq 0.$$

So we have

$$W'_k\left(k^*, \hat{f}\right) \geq 0 = W'_k\left(k^*, f^*\right) = W'_k\left(\hat{k}, \hat{f}\right),$$

which implies $\hat{k} \geq k^*$ by concavity of W with respect to k.

If $\frac{\Phi''_{X,k}}{\Phi'_k} < \frac{\theta^x}{\bar{v}Y}$ then $W''_{k,f} > 0$ and

$$W'_k\left(k^*, \hat{f}\right) < 0 = W'_k\left(k^*, f^*\right) = W'_k\left(\hat{k}, \hat{f}\right),$$

which implies $\hat{k} < k^*$ by concavity of W with respect to k.

Proof of Proposition 2

Consider the case with competitive prices and non-Coasian tariffs. The decentralized outcome coincide with the first best if the tariffs (ρ^m, ρ^x, ψ) verify both Eqs. (10) and (11) and satisfy the zero-profit constraint, $\pi^D = 0$. Notice that the fixed fee does not influence the prosumers' decision but only the profit of the grid. Therefore, to restore the first best, one need to find (ρ^m, ρ^x) such that Eqs. (10) and (11) coincide. Using (7), this implies:

$$\frac{\hat{v}}{\bar{v}} = 2\frac{C'_f + \Phi\rho^x \frac{\partial x_i}{\partial f}}{C'_f + \Phi\theta^x \frac{\partial x_i}{\partial f}}. \tag{A.4}$$

as from (8), with competitive prices $\hat{v} = \rho^m + c - \rho^x \frac{X}{Y}$.

Eq. (A.4) defines a locus Λ of grid tariffs that restore the first best. We can express this locus as:

$$\Lambda := \{\rho^m, \rho^x\} \text{ such that } \rho^m + c = \mathcal{A}\rho^x + \mathcal{B},$$

with

$$\mathcal{A} = \frac{X}{Y} + 2\frac{\Phi\frac{\partial x_i}{\partial f}}{C'_f + \Phi\theta^x \frac{\partial x_i}{\partial f}}\bar{v} > 0,$$

$$\mathcal{B} = 2\frac{C'_f}{C'_f + \Phi\theta^x \frac{\partial x_i}{\partial f}}\bar{v} > 0.$$

The locus Λ is linear, it has an increasing slope ($\mathcal{A} > 0$) and the point $(\rho^m, \rho^x) = (\theta^m, \theta^x)$ does not belong to the locus.

Proof of Proposition 3

Including the subsidy, scheme the prosumer's utility becomes:

$$U_i = S - p^m q + p^m \Phi y_i - (p^m - p^x)\Phi x_i - z y_i - C_f(f_i) - \psi + s(f_i).$$

Maximizing U_i with respect to f_i, for $i = 1, 2$ and writing $f_i = f$, the first order condition is:

$$\frac{\partial U_i}{\partial f} = \Phi'_f \underbrace{\left[p^m y_i - (p^m - p^x)x_i\right]}_{\hat{v}Y/2} - (p^m - p^x)\Phi\frac{\partial x_i}{\partial f} - C'_f + s' = 0$$

Considering the case of Coasian tariffs and competitive prices, this first order condition is similar to the first best condition (Eq. (A.2)) if $s' = \Phi'_f \frac{\bar{v}Y}{2}$. Hence, such a subsidy restore the first best investment in Flex.

Complement to Section 6.1 and proofs of Proposition 4 and Corollary 2

Suppose that $\Phi_1 = 1$ and $\Phi_2 = \Phi(X, k)$ and that energy prices are competitive and grid tariffs are cost reflective. In this context, we have:

$$U_1 = S_1 - (\theta^m + c)(q_1 - y_1) - \theta^x x_1 - z y_1 - C_f(f_1), \tag{A.5}$$

$$U_2 = S_2 - (\theta^m + c)(q_2 - \Phi y_2) - \theta^x \Phi x_2 - z y_2 - C_f(f_2), \tag{A.6}$$

$$W = U_1 + U_2 - C_c(k). \tag{A.7}$$

In this context, the first best (f_1^*, f_2^*) is defined by:

$$C'_f(f_1) = -\frac{\partial x_1}{\partial f_1}\theta^x + \frac{\partial \Phi}{\partial f_1}((\theta^m + c)y_2 - \theta^x x_2), \tag{A.8}$$

$$C'_f(f_2) = -\frac{\partial x_2}{\partial f_2}\Phi\theta^x + \frac{\partial \Phi}{\partial f_2}((\theta^m + c)y_2 - \theta^x x_2). \tag{A.9}$$

While the decentralized outcome $(\hat{f}_1, \hat{f}_2)$ is defined by Eq. (A.9) and

$$C'_f(f_1) = -\frac{\partial x_1}{\partial f_1}\theta^x. \tag{A.10}$$

To restore the first best, the subsidy scheme must be designed as:

$$s_1'(f_1^*) = \frac{\partial \Phi}{\partial f_1}((\theta^m + c)y_2 - \theta^x x_2) > 0, \tag{A.11}$$

$$s_2'(f_2^*) = 0. \tag{A.12}$$

This implies that $C_f'(f_1^*) > C_f'(f_2^*)$ so $f_1^* > f_2^*$.

Suppose that the regulator propose a uniform subsidy $s(f)$ for both prosumers. Then decentralized outcome is:

$$C_f'(f_1) - s'(f_1) = -\frac{\partial x_1}{\partial f_1}\theta^x, \tag{A.13}$$

$$C_f'(f_2) - s'(f_2) = -\frac{\partial x_2}{\partial f_2}\Phi\theta^x + \frac{\partial \Phi}{\partial f_2}((\theta^m + c)y_2 - \theta^x x_2). \tag{A.14}$$

If $s'(f_1) = \frac{\partial \Phi}{\partial f_1}((\theta^m + c)y_2 - \theta^x x_2)$, then $f_1 = f_1^*$ but

$$C_f'(f_2) = -\frac{\partial x_2}{\partial f_2}\Phi\theta^x + \left(\frac{\partial \Phi}{\partial f_2} + \frac{\partial \Phi}{\partial f_1}\right)((\theta^m + c)y_2 - \theta^x x_2). \tag{A.15}$$

The right hand side of Eq. (A.15) is larger than those of (A.9) implying that $f_2 > f_2^*$.

Similarly, if $s'(f_2^*) = 0$ then, we have $f_2 = f_2^*$ and the investment by prosumer 1 is given by Eq. (A.10) implying that $f_1 < f_1^*$ and this proves Proposition 4.

Now suppose that the uniform subsidy is defined as a linear combination of $s_1'(f)$ and $s_2'(f)$ defined in Eqs. (A.11) and (A.12):

$$s'(f) = \alpha s_1'(f) + (1 - \alpha)s_2'(f).$$

This marginal subsidy is increasing in α implying that the investment in Flex of both prosumers increase in α. Given Proposition 4, it is possible to find an $\tilde{\alpha} \in (0, 1)$ such that the total investment in Flex is equal to the first best level: $\hat{f}_1 + \hat{f}_2 = f_1^* + f_2^*$. However, even if prosumers are identical ($y_1 = y_2$ and $x_1 = x_2$), Flex costs are linear in f ($C_f'' = 0$) and the Flex investment has a constant impact on the self consumption ($\frac{\partial^2 hi}{\partial f_i^2}) = 0$, implying that $\frac{\partial x_1}{\partial f_1} = \frac{\partial x_2}{\partial f_2}$), the first best is not a function of the total Flex investment. Indeed, with all these constraints, the first terms in Eqs. (A.8) and (A.9) differ. Hence, the first best does not only depend on the total storage capacity on a given line but also on its repartition among prosumers.

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