Small batteries, big impact: spatiotemporal drivers of grid-compatible residential solar

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Abstract:
The rapid diffusion of residential photovoltaic (PV) systems is reshaping electricity demand profiles worldwide, amplifying mid-day surplus generation while leaving evening demand peaks largely intact. As distributed PV penetration increases, the system-level value of behind-the-meter generation becomes increasingly dependent on its interaction with distribution networks, particularly in the absence of sufficient temporal alignment between generation and demand. Residential battery energy storage systems (BESS) are widely recognised as a key enabler of such alignment; however, their contribution is often assessed through household-level metrics, while their regional and grid-facing impacts remain less systematically characterised. This paper develops a spatiotemporal, regionally resolved framework to evaluate residential PV–battery integration from a power-system perspective, using grid-interaction indicators rather than consumer-centric economic metrics. The approach is applied to a national-scale case study, employing harmonised hourly residential demand, solar resource, and rooftop PV potential data across more than 8,134 local administrative units. PV-only and PV-BESS configurations with storage capacities ranging from 0 to 10 kWh per dwelling are simulated to quantify annual grid imports and exports, peak demand reduction, and mid-day surplus mitigation. Results indicate that relatively small storage capacities (1–2 kWh per dwelling) deliver a significantly greater share of grid-level benefits, substantially reducing both mid-day export volumes and evening peak imports, while larger batteries exhibit diminishing marginal returns. Strong spatial heterogeneity emerges: in dense urban regions, where rooftop PV capacity per dwelling is typically limited, storage primarily functions as a peak-shaving resource, whereas in high-irradiation, low-density areas it mainly mitigates surplus injection into the grid. At aggregate scale, widespread deployment of modest residential storage smooths residual load profiles and reduces ramping requirements without encouraging excessive storage capacity. These findings position residential battery storage as a distributed flexibility resource whose system value is governed by operational impacts and regional context, rather than by self-consumption alone. The proposed framework provides transferable insights for distribution planning and policy development aimed at integrating residential PV and storage into future low-carbon power systems.

Keywords:
Duck curve, Residential BESS, Community self-consumption, Marginal grid relief, Reverse power flow, Distributed energy resources.

1. Introduction

Residential rooftop photovoltaic (PV) systems have undergone rapid growth in recent years, particularly in Europe. Over 2.1 million residential installations were registered by 2023, with annual growth rates exceeding 40% [2] in Spain alone. This expansion has introduced new operational challenges to distribution networks that were not originally designed to handle large volumes of decentralised energy generation. The fundamental issue is a temporal mismatch between demand and generation. Rooftop PV systems produce most of their energy from mid-morning to early afternoon, whereas residential electricity demand reaches its daily maximum in the evening, after solar generation has already ceased. This mismatch produces two separate loading conditions on the low-voltage network. During the central hours of the day, generation that exceeds local consumption is injected back into the grid, raising feeder voltages and creating reverse power flow. In the evening, residential demand peaks while rooftop output has already dropped to zero, so households import heavily from the grid and distribution transformers experience their highest thermal stress [3–5]. The superposition of these two effects produces the characteristic duck-shaped residual load curve that has become a reference concern for distribution system operators in Spain and elsewhere in Europe.

Battery energy storage systems installed together with residential PV (PV-BESS) have been put forward as a means to reconcile generation and demand at the dwelling level. Under the subsidy schemes currently in force in Spain, however, the incentive is proportional to installed capacity in euros per kWh, which encourages prosumers to install systems of 5 to 10 kWh oriented towards maximising individual self-consumption or exploiting tariff period differentials rather than providing temporally coordinated relief to the distribution grid [6, 8].

The literature on BESS sizing and placement for grid support is active but does not yet provide national-scale spatial evidence. Studies that examine single-feeder or single-node systems demonstrate clear peak-shaving benefits in controlled settings but offer limited guidance for designing national policy [20–22]. Work that addresses the spatial variation of PV integration, including studies on over-voltage risk and irradiance mapping, generally does not couple that spatial perspective with a time-resolved battery dispatch [17–19]. Economic analyses of self-consumption and grid interaction are useful for individual consumers but do not answer the infrastructure question that DSOs face: at what capacity does residential storage actually alleviate physical stress on the distribution network [8, 24, 25]. None of these studies has applied such analysis to all municipalities of a large European country simultaneously, so the spatial distribution of the benefit and its dependence on local demand and rooftop characteristics remains largely uncharacterised.

This study addresses this gap. The analysis is applied to all 8,134 Spanish municipalities using harmonised hourly electricity demand from smart meters, satellite-derived solar irradiance from PVGIS, and census-based rooftop geometry. PV-only and PV-BESS systems with battery capacities ranging from 0 to 10 kWh per dwelling are simulated for a full representative year, and the results are evaluated using grid-facing metrics rather than economic or consumer-centric indicators. The analysis demonstrates that a battery of 1 to 2 kWh per dwelling is large enough to capture the great majority of achievable grid relief, and that the benefit of adding further capacity beyond that range falls away sharply. The geographic distribution of grid relief is presented at municipal level, and the implications for the design of residential storage policies in Spain and other countries with similar PV-BESS deployment are discussed.

The remainder of the paper is organised as follows. Section 2. describes the methodology, data sources, and grid-relief metrics. Section 3. covers the diurnal load-shaping results, the spatial distribution of grid relief, the marginal utility analysis, the peak infrastructure stress findings, and the policy recommendations. Section 4. summarises the conclusions.

2. Methodology

The methodological framework for evaluating the effect of BESS in combination with PV on grid stress relief is divided into four sequential stages as shown in Fig. 1. The first stage handles data collection and harmonisation. The second stage simulates PV-BESS dispatch at national level with varying battery storage sizes across all municipalities. The third stage evaluates and quantifies the grid-relief metrics. The fourth stage aggregates the results for spatial mapping, Pareto analysis, and RPF statistics at national level, all of which can serve as a guide for policy and subsidy reforms.

2.1. Data collection and national coverage

Three datasets were collected and harmonised across Spain's 8,134 municipalities at hourly resolution.

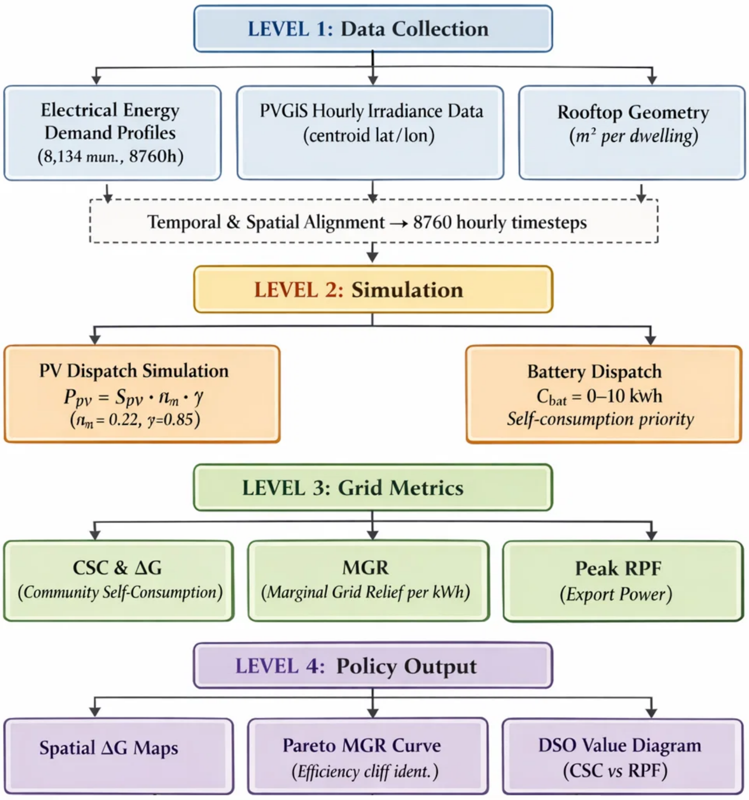

Figure 1: Four-stage methodological framework. Stage 1 collects and harmonises three national datasets to 8,760 hourly timesteps for each municipality. Stage 2 simulates 11 different PV-BESS dispatch configurations (0–10 kWh per dwelling in 1 kWh steps). Stage 3 evaluates grid-interaction metrics (CSC, ΔG, *MGR*, and peak RPF). Stage 4 gives the Pareto analysis, spatial maps, and DSO-value diagram.

2.1.1. Residential electricity demand

Hourly residential electricity demand data were obtained from hourly smart-meter aggregates provided by Datadis [10], which is Spain's national open-data platform for electricity supply and covers more than 90% of domestic contracts. For each municipality i, the per-dwelling average hourly demand $E_{d,i}(t)$ is obtained by dividing total hourly municipal consumption by the number of active residential supply contracts [11]. This normalisation preserves the actual hourly demand profile, including the sharp evening peak which gives rise to the duck curve, and allows municipalities of varied sizes to be compared. The average annual consumption per dwelling in Spain is approximately 2.65 MWh, with urban municipalities recording slightly higher values than rural ones, mainly due to greater floor areas and increased use of air conditioning.

2.1.2. Solar irradiance

The hourly plane-of-array irradiance $G_{T,i}(t)$ was obtained from the European Commission's PVGIS database [12], which provides satellite-derived estimates at various tilt and orientation for any location in Spain. Following the methodology applied in [25] for the evaluation of Spanish residential rooftops, a south-facing configuration with a tilt between 0 and 7 degrees was adopted at the centroid of each municipality. The data were kept at hourly resolution because the value of storage for the grid is governed by the hour-by-hour correspondence between generation and consumption rather than by annual energy totals [7].

2.1.3. Rooftop PV potential

Usable rooftop area per dwelling $S_{PV,i}$ is inferred from the 2021 building census of INE [11], following the residential typology segmentation described in [1]. According to that framework, and consistent with values reported in [25], the mean usable roof area is approximately 5.2 ± 1.98 m^2 for urban municipalities and 9.2 ± 1.25 m^2 for rural ones. This difference in available rooftop area leads to a proportional difference in PV generation potential per dwelling, and that contrast is a key driver of the spatial heterogeneity discussed in Section 3.2..

2.2. PV–battery dispatch simulation

For each municipality i, a fleet of identical residential PV-BESS units, one per dwelling, was simulated. The simulation is implemented in Python using the hourly storage array for each municipality, timestep, and battery scenario. PV capacity per dwelling is calculated as

$$P_{PV,i} = S_{PV,i} \cdot \eta_m \cdot \gamma, \tag{1}$$

where $\eta_m = 0.22$ is the module efficiency and $\gamma = 0.85$ aggregates the losses from tilt derating, soiling, and balance-of-system inefficiency. Battery capacity C_{bat} is then swept across integer values from 0 to 10 kWh per dwelling, giving 11 scenarios in total. For the primary results, the analysis focuses on the 0 to 4 kWh range because the benefits above 4 kWh are shown to be negligible in Section 3.3..

At each scenario, a full-year hourly dispatch applies a self-consumption priority strategy. PV generation first serves the local load directly. Any generation surplus then charges the battery at a charging efficiency of $\eta_c = \sqrt{0.90}$. Any surplus that remains after the battery is full is exported to the grid. When load exceeds generation, the battery discharges at $\eta_d = \sqrt{0.90}$ until it is depleted, and any remaining deficit is then met by grid import.

The round-trip efficiency of $\eta_{rt} = 0.90$ has been implemented symmetrically as $\sqrt{\eta_{rt}}$ on each half-cycle, which is consistent with standard lithium-ion battery modelling practice [16]. The state of charge at each timestep is bounded within $[0, C_{bat}]$.

The simulation output for each municipality i and scenario n is a pair of hourly time series over 8,760 hours, covering grid import $G_{imp,n,i}(t)$ and grid export $G_{exp,n,i}(t)$, both expressed in kWh per dwelling, and per-municipality hourly values are then scaled by the contract count $N_{c,i}$ to obtain municipal-level energy flows and finally aggregated nationally.

2.3. Grid relief metrics

Four metrics are computed from the simulation outputs.

2.3.1. Community Self-Consumption

The Community Self-Consumption (CSC) for municipality i under battery scenario n is calculated as

$$CSC_{n,i} = 1 - \frac{\sum_{t=1}^{8760} G_{imp,n,i}(t)}{\sum_{t=1}^{8760} E_{d,i}(t)}, \tag{2}$$

which expresses the fraction of annual residential demand that is met by local sources. CSC is bounded within $[0, 1]$ and requires no tariff assumptions to evaluate.

2.3.2. Grid Relief Potential

The Grid Relief Potential (ΔG) is the absolute improvement in CSC attributable to battery storage, measured against the PV-only baseline, and is given by

$$\Delta G_{n,i} = CSC_{n,i} - CSC_{0,i}. \tag{3}$$

For example, $\Delta G_{n,i} = 0.20$ indicates that adding n kWh of battery per dwelling shifts 20 percentage points of annual residential demand from grid import to local sources, with a corresponding reduction in transformer loading and feeder losses.

2.3.3. Marginal Grid Relief

The Marginal Grid Relief (*MGR*) is the incremental national average CSC gain per additional kWh of battery capacity and is defined as

$$MGR_n = \overline{CSC}_n - \overline{CSC}_{n-1}, \tag{4}$$

where $\overline{CSC}_n = \left(\sum_i w_i \cdot CSC_{n,i}\right) / \left(\sum_i w_i\right)$ is the population-weighted national average and w_i is the resident count of municipality i. Population weighting is essential because a municipality of 500,000 residents places roughly 500 times more load on its substation than a village of 1,000, and the national metric should reflect that physical reality.

2.3.4. Peak Reverse Power Flow

Grid export during peak PV generation hours creates reverse power flow on distribution transformers, and the peak magnitude of that flow governs thermal stress and determines whether a capital upgrade is required [14, 23]. The per-municipality peak RPF is defined as the 99th percentile of aggregate hourly export,

$$RPF_{n,i} = \underset{t}{\mathrm{P99}}\left[G_{exp,n,i}(t) \cdot N_{c,i}\right] \quad \text{[kW]}, \tag{5}$$

where $N_{c,i}$ is the number of active contracts. The 99th percentile is preferred over the absolute maximum because it reduces sensitivity to isolated data artefacts while still capturing the stress events that govern infrastructure design. The population-weighted national representative value is

$$\overline{RPF}_n = \frac{\sum\limits_i w_i \cdot RPF_{n,i}}{\sum\limits_i w_i} \quad \text{[kW]}, \tag{6}$$

which is interpreted throughout this paper as the peak RPF stress on a representative Spanish municipal feeder cluster rather than on any single physical transformer or on the national transmission aggregate. The percentage reduction in this quantity is

$$PR_n = \left(1 - \frac{\overline{RPF}_n}{\overline{RPF}_0}\right) \times 100\,\%. \tag{7}$$

3. Results and discussion

3.1. Diurnal load-shaping and the duck curve

Understanding how PV-BESS changes the dynamics of the national demand shape requires distinguishing between two physically distinct mechanisms. The first is the absorption of the midday export surplus, which governs voltage stability on the low-voltage feeders. The second is the discharge of stored energy into the evening import ramp, which governs thermal loading on distribution transformers. These two mechanisms are not interchangeable, and treating them as a single aggregate effect would obscure the most policy-relevant finding of the analysis. Fig. 2 presents the annual mean diurnal profile of national grid demand and residential energy flows, structured to make both mechanisms simultaneously visible.

The no-PV reference case, drawn as a black solid line, shows a demand pattern that is typical of residential-dominated networks in southern Europe. During the morning, demand rises moderately from its overnight minimum and levels off at around 09:00 in what is referred to as the morning shoulder in load-profile analysis – a period of relatively stable intermediate demand before the main evening rise. Demand then climbs steeply from the late afternoon onward, reaching a pronounced evening peak between 20:00 and 22:00 that varies from approximately 25 GW in the lower-demand

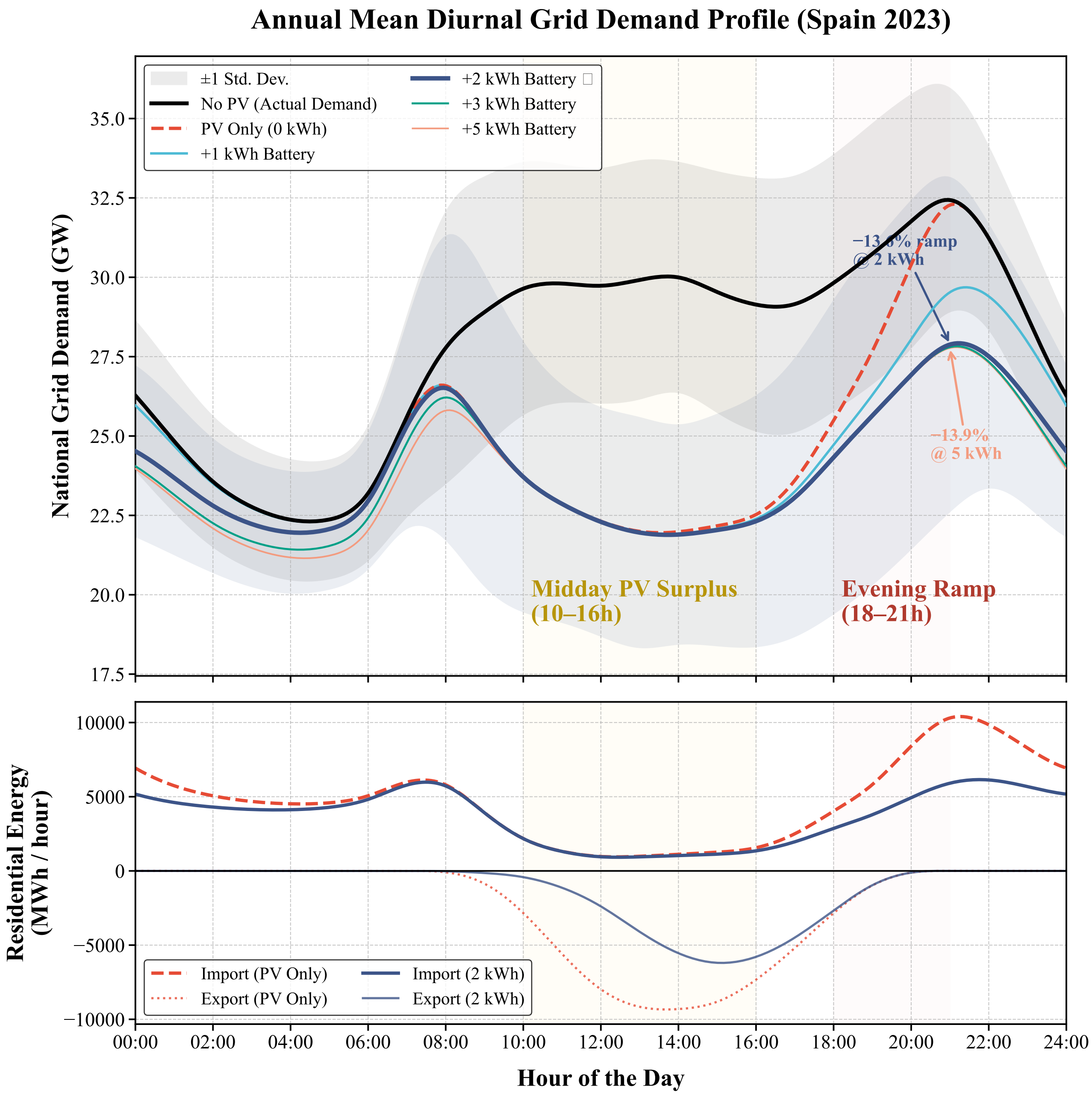

Figure 2: Annual mean diurnal grid demand and residential energy profile for Spain (2023). Upper panel shows national grid demand in GW for six scenarios from no PV (black solid) through 5 kWh storage (orange), with a ± 1 standard deviation seasonal band in grey. The midday surplus window (10–16h, yellow shading) and evening import ramp (18–21h, red shading) are annotated, along with the evening-peak reduction for 2 kWh (-6.5%) and 5 kWh (-6.6%) relative to PV-only. Lower panel shows residential hourly import (solid) and export (dotted) for PV-only (red) and 2 kWh storage (blue), in MWh per hour, showing the simultaneous reduction of the midday export trough from approximately $-9{,}000$ MWh/h to $-1{,}500$ MWh/h and the corresponding flattening of the evening import peak.

winter months to around 32 GW during warmer periods with higher cooling loads. Together, the morning shoulder and the evening peak give the daily demand curve its characteristic two-stage shape. The PV-only scenario, shown as a red dashed line, reduces the demand visible to the network during the midday hours, because a share of residential load is met directly by rooftop generation rather than by grid import. In the 10:00 to 16:00 window, however, generation in many municipalities exceeds local demand, and the net balance turns negative: power flows from the prosumer back into the low-voltage feeder rather than in the other direction. This export surplus, shown below the zero line in the lower panel of Fig. 2, is what gives rise to the duck-curve profile. The evening peak in the PV-only case is barely changed relative to the no-PV reference, because generation has already fallen to zero by the time evening demand develops.

Adding 1 kWh of battery per dwelling reduces both the export surplus and the evening import at the same time. During the midday window the battery charges, absorbing energy that would otherwise flow back into the network. It then discharges in the evening as grid import demand grows. At 2 kWh per dwelling, the evening peak import is 6.5% lower than in the PV-only case, and the export trough in the lower panel contracts from approximately $-9{,}000$ MWh/h to around $-1{,}500$ MWh/h. That export reduction is particularly critical because it is the surplus injection that directly generates over-voltage risk by increasing reverse active power flow on low-voltage feeders [17, 19].

What is equally revealing is what happens beyond 2 kWh. Increasing battery capacity to 5 kWh reduces the evening peak by only 6.6%, a figure that is essentially identical to the 2 kWh result. The additional 3 kWh of hardware has delivered virtually no further evening ramp flattening. This saturation provides an intuitive early indication of the diminishing returns that are quantified more rigorously in Section 3.3.. The ± 1 standard deviation band is also substantial at roughly ± 5 GW across most hours, which reflects the strong seasonal variation in PV generation. The mean-year analysis therefore represents a moderate condition.

3.2. Spatial distribution of grid relief

The diurnal analysis in Section 3.1. describes average national behaviour. Grid stress is, however, geographically heterogeneous, and understanding where battery-induced relief concentrates spatially is as important as knowing its national magnitude. To explore this, and to verify that the diminishing-returns effect is not simply an artefact of national averaging, Figs. 3 and 4 map the incremental and absolute CSC across all 8,134 municipalities for four representative storage scenarios.

Three patterns emerge from these maps. The first is universality. Meaningful gains in ΔG appear in every province regardless of climate zone. The interior Meseta, the Atlantic northwest, and the Mediterranean coast all show substantial improvements when moving from PV-only to 1 kWh, which confirms that micro-storage is viable as a nationally deployed grid strategy.

The second pattern is spatial heterogeneity in the operational role of the battery. The highest absolute ΔG values, approaching 45 pp at 2 kWh, are found in the high-irradiance rural and semi-rural municipalities of the south and east, particularly in Andalucía, Murcia, and parts of Extremadura. In these municipalities, the usable rooftop per dwelling commonly exceeds 9 m^2 [25], which means that rooftop PV systems produce substantial midday surpluses. Even a 1 to 2 kWh battery can absorb almost the entire surplus in such a setting, and therefore the battery operates primarily as a surplus-absorption mechanism that mitigates the voltage-raising reverse power flows on rural low-voltage feeders. In dense urban municipalities, where usable rooftop per dwelling is typically restricted to 3 to 5 m^2, PV generation per dwelling is proportionally smaller. The battery in these locations operates with less surplus to absorb, and its principal contribution shifts towards using whatever charge it accumulates during the afternoon to clip the evening import peak, which is a peak-shaving role rather than a surplus-suppression one. This functional distinction between rural surplus absorption and urban peak shaving has been documented conceptually in the self-consumption literature [7, 8, 25], and the maps here provide spatial evidence of it at national scale.

The third and most policy-relevant pattern is the visual plateau visible in both figures. The colour

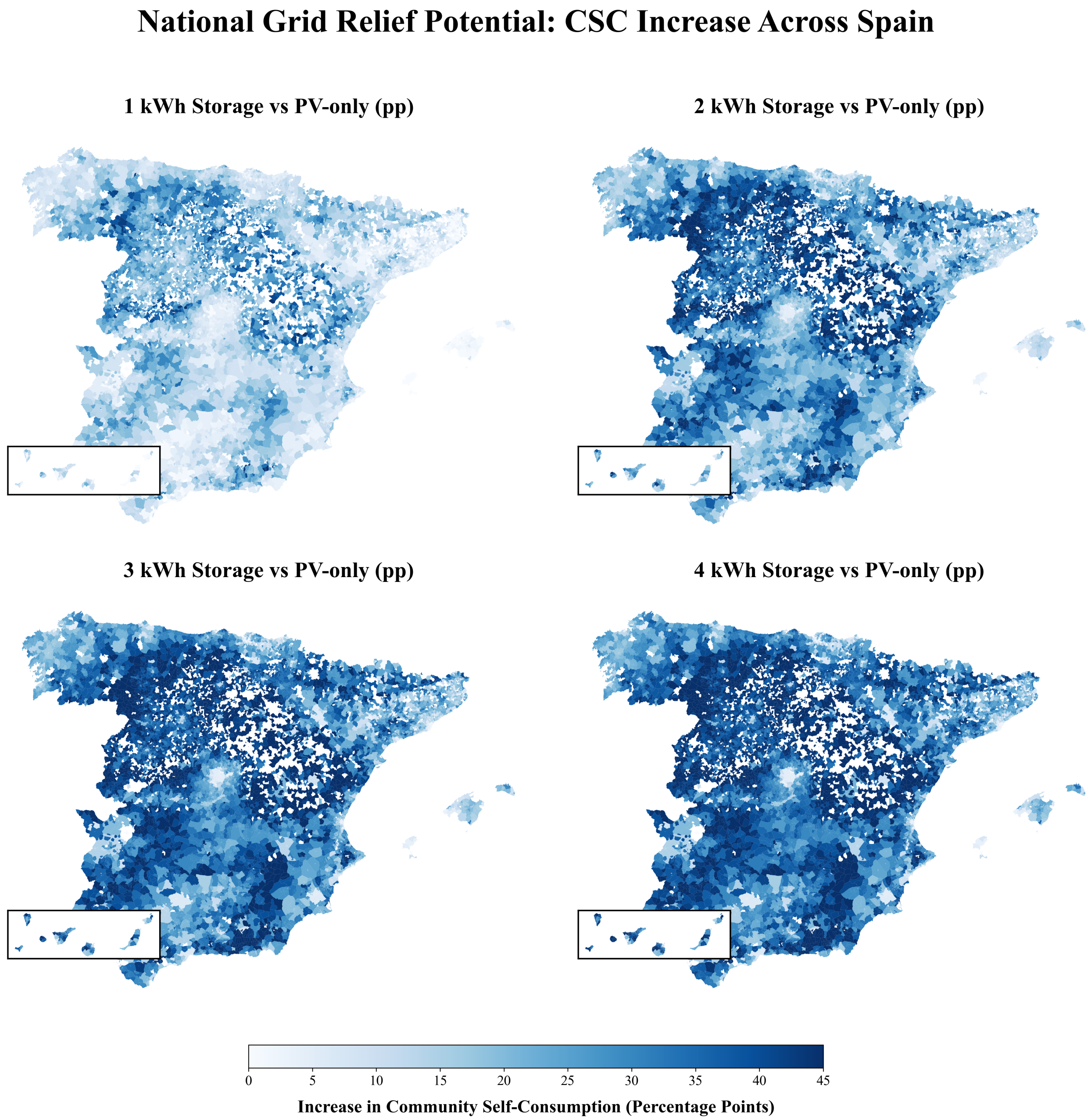

Figure 3: Spatial distribution of grid relief potential (ΔG), showing the increase in Community Self-Consumption in percentage points relative to the PV-only baseline for 1, 2, 3, and 4 kWh storage per dwelling. The colour scale runs from white at 0 pp to dark blue at 45 pp. The Canary Islands inset is shown at the lower-left of each panel. The near-identical colouration of the 3 kWh and 4 kWh panels across all 52 provinces provides spatial evidence of the plateau in marginal returns that is identified quantitatively in the aggregate Pareto analysis.

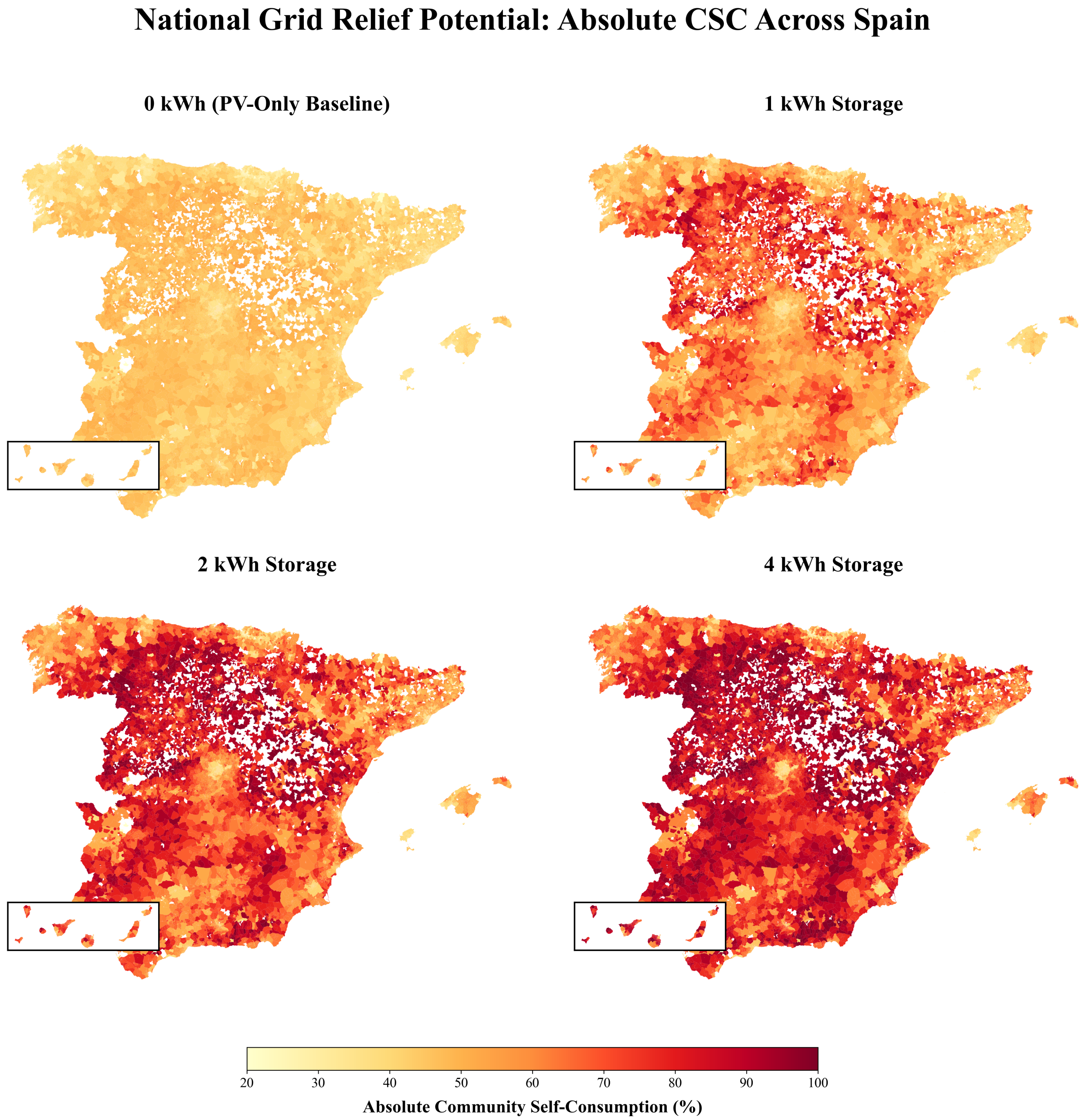

Figure 4: Spatial distribution of absolute Community Self-Consumption in percentage for four battery scenarios covering 0 kWh (PV-only baseline), 1, 2, and 4 kWh per dwelling. The colour bar ranges from pale yellow at 20% to deep red at 100%. The 2 kWh and 4 kWh results are spatially consistent across the entire peninsula, confirming that the diminishing-returns pattern observed in the national aggregate holds at individual municipal resolution.

distributions in the 3 kWh and 4 kWh panels of Fig. 3 are nearly indistinguishable across the entire territory, and Fig. 4 shows that the 2 kWh and 4 kWh absolute-CSC maps are spatially consistent, with the deep-red high-CSC zones fully established by 2 kWh. This pattern is observed across all climate zones and municipality types in the dataset, from the high-irradiance municipalities of the south to the Atlantic northwest and the interior Meseta. This indicates that the plateau in grid relief is linked to the physical characteristics of residential demand and rooftop generation in Spain, rather than to the way in which municipal data are aggregated at national level. Verifying this finding at finer spatial resolution, for example at the level of individual feeders or census sections, would be a useful extension of the analysis.

3.3. The marginal utility cliff and cumulative efficacy

For the marginal utility and cumulative analysis, the population-weighted national average MGR has been computed and the values are shown as bars on the left axis, plotted alongside the cumulative fraction of total achievable relief on the right axis, for each 1 kWh increment from 0 to 10 kWh as shown in Fig. 5.

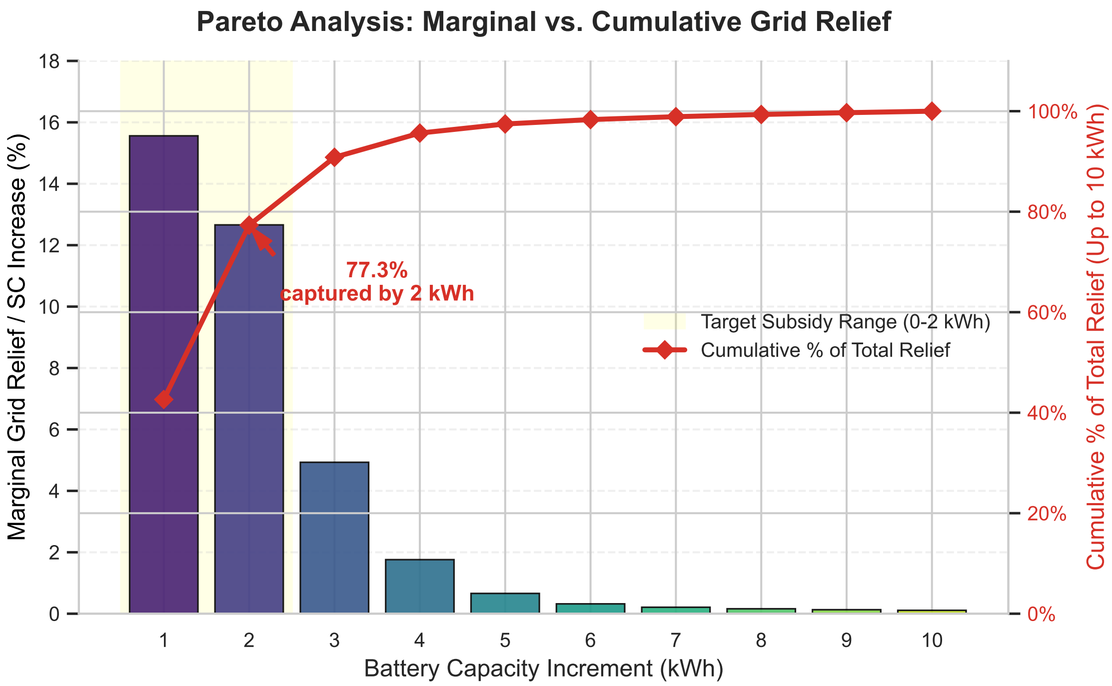

Figure 5: Pareto analysis of Marginal Grid Relief (*MGR*) and cumulative efficacy. The bars on the left axis show the *MGR* in percentage points per 1 kWh battery increment. The red diamond curve on the right axis shows the cumulative fraction of total achievable relief normalised to the 10 kWh scenario. The yellow shading identifies the region of highest marginal return from 0 to 2 kWh, where 77.3% of the maximum achievable grid relief is captured.

As shown in Fig. 5, the first kilowatt-hour of battery storage delivers 15.6 pp of national average grid relief, an enormous gain relative to the PV-only baseline that reflects the high temporal overlap between the narrow window of peak PV export surplus around 12:00 to 15:00 and the filling capacity of a 1 kWh battery. The second kilowatt-hour adds 12.6 pp, which is still a substantial improvement. Together, these two increments capture 77.3% of the total relief achievable with a 10 kWh system.
After the first 2 kWh, a steep decline is evident. The third kilowatt-hour contributes approximately 5.0 pp, which is less than 40% of what the second kilowatt-hour delivered. The fourth adds only 1.8 pp. At 5 kWh the MGR is only 0.6 pp, and above 5 kWh the values drop below 0.3 pp per step. The largest single fall occurs between 2 and 3 kWh, where the MGR drops from 12.6 pp to 5.0 pp, a reduction of more than 60% in one step. At 4 kWh the value is 1.8 pp, less than one seventh of the 1 kWh result.

To understand why the grid benefit falls away so quickly, it helps to consider what the battery is actually doing at each capacity level. In the 1 to 2 kWh range, the battery charges during the hours of highest PV generation, when local output reliably and substantially exceeds residential demand in most municipalities. The stored energy is then discharged in the early evening when import demand is high. These are the hours when the mismatch between generation and demand is at its most pronounced, and a small battery can therefore make a large difference. Above 2 kWh, the battery has already covered those most productive hours. To charge further, it must draw on periods when the generation surplus is smaller and shorter – the later morning or earlier afternoon when irradiance is still building or already falling. Similarly, the battery can only discharge usefully in the evening until residential demand is satisfied, after which additional capacity provides no further grid benefit. The result is that each additional kilowatt-hour above 2 kWh has progressively less useful work to do within the daily cycle.

The cumulative efficacy curve contextualises this clearly. Scaling from 2 kWh to 10 kWh requires approximately a 400% increase in deployed hardware but provides only 22.7% of additional grid relief. In Spain's residential sector, with its current PV penetration and energy demand profile, battery storage provides the greatest grid value at 1–2 kWh per dwelling; beyond that range, additional capacity yields diminishing returns.

3.4. Peak infrastructure stress alleviation

While CSC and ΔG measure volumetric energy relief, distribution infrastructure is fundamentally constrained by peak power capacity. A transformer or feeder cable has a thermal rating, and it is the peak instantaneous load rather than annual energy throughput that determines whether a capital upgrade is required [14]. For a DSO, the question is not how much energy is self-consumed annually but whether the battery prevents the worst-case export events that trigger transformer replacement orders. Fig. 6 addresses this question directly.

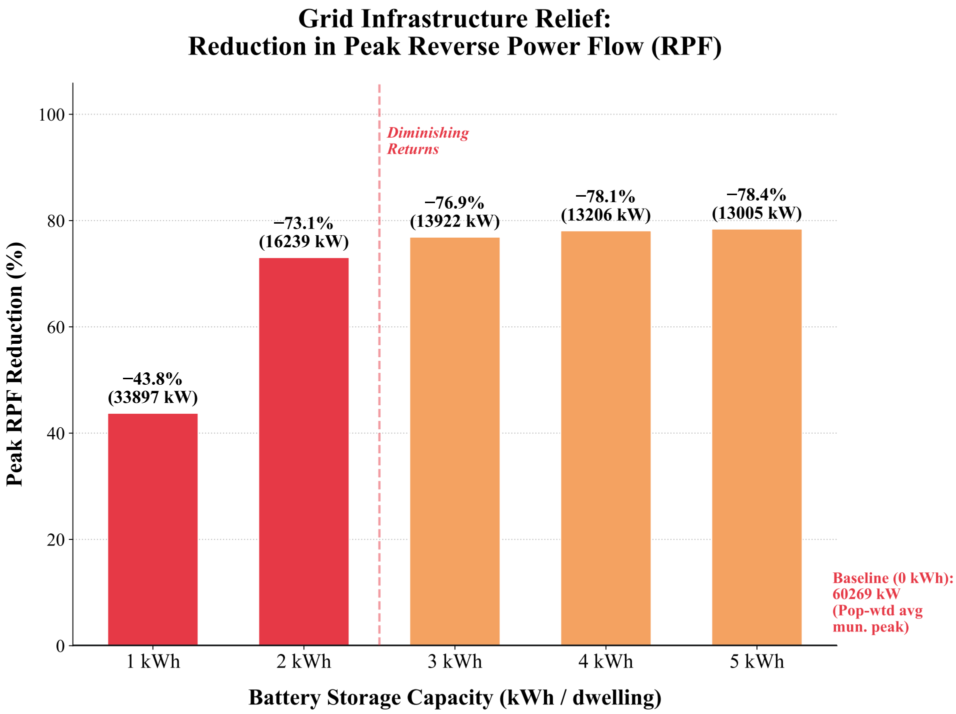

Figure 6: Reduction in peak Reverse Power Flow as a function of battery capacity per dwelling. The PV-only baseline corresponds to a population-weighted average peak RPF of 60,269 kW, computed as the 99th-percentile aggregate export across all 8,134 municipalities. Each bar indicates the percentage reduction relative to the baseline and the resulting absolute peak RPF. The vertical dashed line at 2.5 kWh separates the high-return region (red bars, left) from the region of diminishing returns (orange bars, right).

The baseline population-weighted average peak RPF under the PV-only scenario is 60,269 kW. This quantity represents the aggregate peak export stress on a representative Spanish residential municipal feeder cluster, which is computed as the population-weighted mean of per-municipality 99th-percentile export flows scaled by contract count as defined in Eq. (6). It is not the RPF on any single physical transformer or on the national transmission system.
Even 1 kWh of storage reduces this by 43.8% to 33,897 kW. The reduction is large because the peak export window is temporally narrow. During the peak irradiance hours of 12:00 to 14:00, even a small battery fills quickly and begins clipping the steepest part of the export spike.
The addition of a second kilowatt-hour extends this clipping action further into the midday surplus window, reducing the peak RPF by 73.1% to 16,239 kW. This represents roughly a 1.7-to-1 leverage of battery capacity to peak-power relief. These results highlight the value that small storage systems can provide to DSOs. When aggregated over a sufficient number of connected dwellings, a deployment at this capacity level can postpone transformer reinforcement investments that would otherwise be required to accommodate the export peaks observed on clear summer days.

The same saturation pattern visible in the volumetric results (Fig. 5) appears in the peak-power metric (Fig. 6). Adding a third kilowatt-hour reduces the population-weighted peak RPF by only 3.8 additional percentage points (from 73.1% to 76.9%), and the interval from 3 to 5 kWh contributes a combined 1.5 percentage points. Each additional unit of capacity beyond 2 kWh therefore yields progressively less infrastructure value. For a distribution operator seeking to minimise peak export stress per euro of subsidy, allocating 2 kWh to each of five dwellings delivers a larger aggregate reduction than concentrating 10 kWh in a single dwelling, and it does so over a wider section of the network.

3.5. Policy recommendations

Both the volumetric and the peak-power analyses converge on the same capacity boundary. With 2 kWh per dwelling, 77.3% of the total achievable grid relief is already captured and the population-weighted peak RPF is reduced by 73.1%; beyond this point, every additional kilowatt-hour adds less than four percentage points to either metric. On this basis, three adjustments to the current subsidy framework are proposed. The first is to cap the grid-support component of the incentive at 2 kWh per dwelling, since capacity installed above this level serves private self-consumption objectives rather than measurable infrastructure relief. It continues to benefit the individual consumer through self-consumption and bill reduction, but those are consumer-economic benefits rather than infrastructure benefits. Subsidising additional capacity beyond 2 kWh from a grid-investment budget is therefore not justified by the evidence. The ceiling should apply only to the grid-support component of the incentive scheme. Prosumers who prefer to install larger systems for backup or for economic reasons should remain free to do so at their own expense.
The second recommendation is to introduce a progressive rate, highest for the first kWh and lower for the second, falling to zero beyond 2 kWh. This would make the 2 kWh system the most attractive option for prosumers under the current self-consumption (*autoconsumo*) regulation [6] without requiring that outcome to be mandated, and would also remove the existing incentive to install larger systems for economic optimisation alone.
The third adjustment is geographic prioritisation. Figs. 3 and 4 show that grid relief potential is highest in the high-irradiance municipalities of southern Spain, particularly Andalucía, Murcia, and Extremadura, and in the densely populated coastal and urban municipalities where evening import stress is most pronounced. An additional percentage on the subsidy rate for municipalities where evening import stress exceeds a defined threshold would concentrate public expenditure in the areas where each euro invested yields the greatest reduction in distribution infrastructure loading.
Together, these three adjustments would redirect existing subsidy budgets towards the capacity range and geographic locations where the grid benefit per euro is highest, without requiring additional total

expenditure.

4. Conclusion

This study has evaluated the grid-level effect of residential battery storage across all 8,134 Spanish municipalities, using harmonised hourly electricity demand from smart meters, hourly irradiance from PVGIS, and rooftop geometry from the national building census. Battery capacity was varied from 0 to 10 kWh per dwelling and the results assessed using three grid-facing metrics: Community Self-Consumption, grid relief potential, and peak Reverse Power Flow.

Results show that the first 2 kWh of battery capacity per dwelling captures 77.3% of the total achievable grid relief and reduces the population-weighted average peak RPF by 73.1%. Above this level, each additional kilowatt-hour contributes less than 5 pp of further volumetric relief and less than 4% of further peak-power reduction. The largest single fall in marginal benefit occurs between 2 kWh and 3 kWh. The analysis also shows that this pattern holds at individual municipal resolution across all 52 Spanish provinces, rather than being a product of national-level aggregation.

A functional distinction between municipality types has also been identified. In rural, high-irradiance municipalities where rooftop area per dwelling is large, the battery operates primarily as a surplus-absorption mechanism that reduces midday reverse power flow. In denser urban municipalities with smaller rooftop areas, the battery's role shifts towards evening peak shaving. Both functions are valuable from a grid perspective, and both are captured within the 1 to 2 kWh capacity range.

The main limitation of the study is that the RPF metric used here is a proxy derived from aggregated municipal export flows rather than a direct power-flow calculation on a physical network. Future work should couple this national-scale simulation with representative distribution-network models to verify the infrastructure-deferral claims quantitatively and to account for line impedances, cable ratings, and transformer capacities. In addition, a full sensitivity analysis covering module degradation, heat-pump load growth, and winter-only operation should be conducted by re-running the complete dispatch model under each stress condition.

In practical terms, splitting a fixed battery investment across five dwellings at 2 kWh each yields more total grid benefit than concentrating it in a single 10 kWh installation, and it does this across a wider part of the distribution network. The 2 kWh capacity identified here thus provides a quantitative basis for setting subsidy caps and for designing progressive-rate incentive structures that are grounded in the actual grid-relief data rather than in assumptions about optimal prosumer system size.

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Nomenclature

Latin symbols

C_{bat} battery capacity per dwelling, kWh
$E_{d,i}(t)$ per-dwelling hourly demand of municipality i, kWh
$G_{T,i}(t)$ hourly plane-of-array irradiance, W/m^2
G_{imp}, G_{exp} hourly grid import / export, kWh
$N_{c,i}$ number of active residential contracts
$P_{PV,i}$ PV capacity per dwelling, kW
$S_{PV,i}$ usable rooftop area per dwelling, m^2
w_i population of municipality i

Greek symbols

γ balance-of-system loss factor

η_c, η_d charging / discharging efficiency

η_m module efficiency

η_{rt} round-trip efficiency

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