A Demand-Side Alternative to Renewable Curtailment: Natural Field Experimental Evidence from Two Countries*

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Abstract

As renewable generation plays a growing role in the energy system, periods of negative wholesale electricity prices are becoming increasingly common and are intended to grow dramatically over the next ten years. Traditionally, system operators respond by paying generators, especially renewables, to curtail production, or mandating that they do so without compensation. In this study, we propose and test a novel alternative: exposing consumers to free and negative prices to stimulate demand when supply is abundant. We implemented large-scale natural field experiments simultaneously in Great Britain and Spain, randomizing 120,000 residential customers to receive varying financial incentives to “turn up" their electricity. We found that demand increased substantially as prices fall to zero, but paying customers to consume beyond free yielded little additional response. Households with electric vehicles and rooftop solar had a larger elasticity than households without such technologies, suggesting demand turn-up is complementary to electrification. In Great Britain, consumption was largely shifted from adjacent hours, while in Spain the increase appeared to represent net new demand. We develop a welfare framework showing conditions under which demand turn-up improves on curtailment; we find that by inducing additional consumption in periods and locations where the marginal cost of supply is low, demand turn-up generates welfare gains that arise from increased electricity consumption where and when marginal cost is low.

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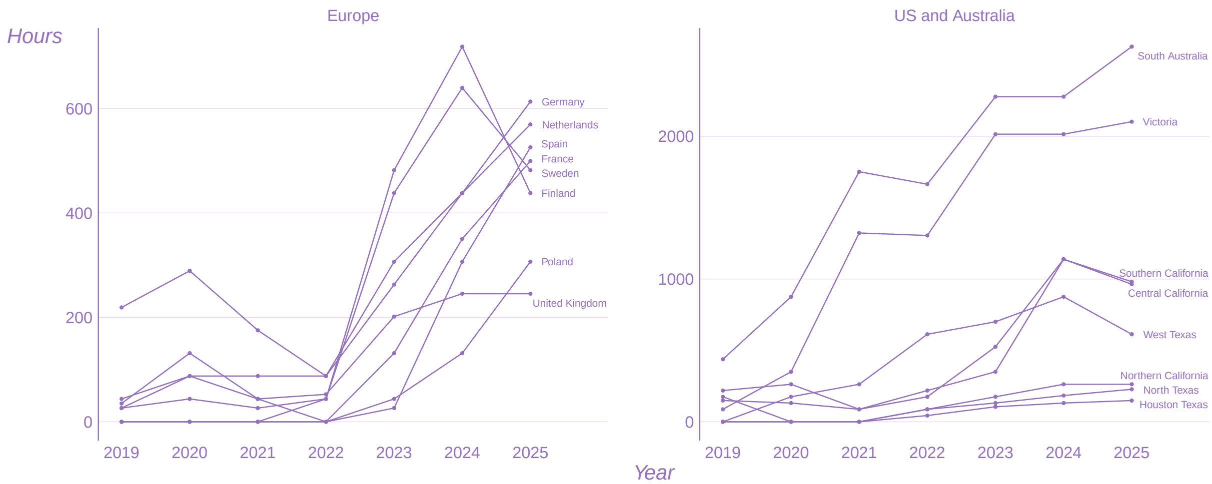
1 Introduction

In 2025, for the first time, wind and solar generation surpassed fossil fuels in the European Union's electricity supply. This milestone marks a new phase of the energy transition. The central challenge is not just whether renewable capacity can be built, but how to integrate large volumes of intermittent generation into power systems designed for stable, dispatchable plants. Europe is an early mover, but not an outlier. As renewable penetration rises globally, power systems around the world will confront the same question: how to align demand with increasingly abundant and intermittent supply.

One indicator of this new phase is the growing frequency of negative wholesale price episodes (Figure 1). Negative wholesale prices reflect periods of extreme surplus, when generators are effectively paying to supply electricity rather than receiving payment for it. These extremes pose new challenges for policymakers. One example is the challenge of the grid's voltage stability. Voltage, the electrical potential that drives current through the network, must be maintained within defined limits to ensure safe and reliable operation. Oversupply during periods of low demand can cause voltage levels to rise beyond acceptable limits (Godwin and Oliver, 2025). Recent system disturbances in Europe, including the 2025 Iberian blackout, have heightened attention to the challenges of maintaining voltage control in high-renewable systems.

Despite these periods of oversupply, low or negative prices are rarely passed on to consumers. Instead, system operators have historically relied on curtailment to manage periods of excess supply. But policymakers have been increasingly exploring demand-side flexibility as an alternative mechanism for restoring balance, one that utilizes surplus electricity rather than avoiding generating it. This mechanism could be done either through passing real-time wholesale prices to consumers, or through coordinated periods in which system operators and retailers incentivize increased consumption. In fact, policymakers are already experimenting with such approaches. In Australia, the federal government has announced a program where retailers must offer households at least three hours of free daytime electricity. In Great Britain, the National Energy System Operator and regional Distribution System Operators have introduced dedicated "turn-up" flexibility services that pay consumers to increase demand when renewable generation is abundant. In addition, the UK Department for Energy Security and Net Zero (2026) is launching a new trial to test removing levies (non-energy costs) during periods of high wind supply.

Figure 1: Hours with negative wholesale electricity prices
Selected regions in Europe, US, and Australia



Notes: Data from International Energy Agency on number of hours with negative wholesale prices in selected regions from 2019 to 2025.

While policy interest has increased, the existing research relies largely on surveys or simulated responses, offering limited evidence from real-world implementation. Without credible causal estimates of consumer responsiveness, policymakers cannot reliably evaluate whether turn-up programs are a cost-effective substitute for curtailment. To address this gap, we implemented twin nationwide natural field experiments in partnership with Octopus Energy Limited in Great Britain and Octopus Energy España, S.L.U. in Spain. We conducted ten pre-specified "turn-up" events, five in each country, between June and September 2025. Events were triggered when day-ahead wholesale electricity prices were forecast to be near zero or negative, aligning the interventions with periods of anticipated excess renewable generation.

The field experiments were conducted at scale, allowing precise estimation of consumption responses under real market conditions; we targeted 120,000 residential customers, split evenly across the two countries. During each event, customers were randomized into either discount on their electricity use, free electricity, negative prices that paid customers to consume additional electricity, or a monetary prize draw. Customers were informed of the event timing and their assigned incentive 24 hours in advance via email. The events lasted one hour in Great Britain and two hours in Spain.

We also ran a separate trial responding to localized network constraints rather than national wholesale conditions. Northern Powergrid (NPG), a Distribution Network Operator in northern England, faces recurring periods where local renewable generation exceeds what the distribution network can accommodate. NPG procured demand turn-up services from Octopus Energy customers in two constrained grid areas, triggering events based on real-time network conditions between January and March 2025. Unlike the main trials, customers first signed up to the program and then opted into individual events. We randomized invitations among 14,477 enrolled customers across 15 event days, offering free electricity for the event duration. This trial provides evidence on two additional questions: whether residential demand flexibility can address localized grid constraints, and how requiring sign-up and event-level opt-in affects the volume and cost-effectiveness of turn-up achieved.

1.1 Primary findings

We report four main sets of findings. First, electricity demand increases substantially when prices fall from the standard rate to a 50 percent discount and then to free electricity, but the marginal response of moving from free to negative prices is small. In Great Britain, offering a 50 percent discount increased hourly electricity consumption by 0.049 kWh (14 percent relative to control). Making electricity free more than doubled this effect, increasing consumption by 0.106 kWh (31 percent). Adding a 5 pence per kWh payment on top of free electricity produced only a modest additional increase to 0.115 kWh (34 percent), and raising the payment to 15 pence per kWh did not generate further meaningful gains (0.116 kWh, 34 percent).

Expressed as point elasticities evaluated at the control price, these effects correspond to an elasticity of -0.28 under a 50 percent discount, -0.31 when electricity is made free, -0.28 for free plus 5p (a 125 percent price reduction relative to baseline), and -0.21 for free plus 15p (175 percent). Economically, the key result is that responsiveness flattens once the price reaches zero.

Spain exhibits the same qualitative pattern, with smaller magnitudes. A 50 percent discount increased hourly consumption by 0.025 kWh (7 percent), while free electricity increased consumption to 0.051 kWh (13 percent). Adding a 10 euro cent payment raised the effect only slightly to 0.054 kWh (13 percent). The prize draw produced an effect comparable to the 50 percent discount. The corresponding point elasticities are -0.12 in magnitude under a 50 percent discount, -0.12 when electricity is free, and -0.07 under free plus 10 cents. Taken together, these results suggest that the primary behavioral response is driven by the transition from paying a positive price to paying zero, rather than by the size of additional financial rewards once electricity is already free.

The results from the localized constraints trial with NPG were closely aligned with the national British trial results. Among customers who signed up to the program and were notified to participate in events, in-event consumption increased by 0.417 kWh. About 20% of customers originally invited to the program had signed up, implying an effect of approximately 0.08 kWh per invited customer. This is similar in magnitude to the 0.105 kWh effect observed in the Free electricity group in the GB trial, where all customers were invited without any sign-up requirement. The sign-up design was more cost-effective: by restricting payments to customers who actively chose to participate, it avoided compensating customers who were unaware of events or did not change their behavior, reducing the payments per kWh of induced demand from £1.21 in the national British trial to £0.75 in the NPG trial.

Second, customers with electric vehicles and rooftop solar exhibit substantially larger treatment effects than households without these technologies in Great Britain.[1] The pattern is particularly pronounced among electric vehicle owners, who can rapidly increase charging during event windows. Similarly, customers on time-of-use tariffs respond more strongly than those on flat tariffs. These findings indicate that demand turn-up is complementary to low-carbon technology: as households adopt flexible electric technologies, the potential to align demand with periods of abundant renewable supply increases.

Third, in Great Britain we observe evidence of intertemporal substitution, whereby customers shift consumption from surrounding hours into the event window. As a result, the increase in demand during Turn-Up events is largely offset by reductions before or after the event, yielding no statistically significant net increase in total consumption. In contrast, in Spain we observe net demand creation, with event-period increases not offset in adjacent hours. This distinction has important economic and environmental implications. If consumption in Great Britain is reallocated away from higher-price, higher-emissions periods toward hours with abundant renewable supply, such substitution may reduce procurement costs and lower the carbon intensity of electricity use.

Fourth, we develop a partial welfare framework to evaluate when demand turn-up (DTU) improves welfare relative to curtailment in electricity systems with surplus generation and network constraints. The model combines experimental estimates of short-run demand responsiveness with institutional features of electricity markets, including sub-

[1] Many EV and solar customers in Spain were participating in other flexibility programs and therefore were excluded from our turn-up trial.

sidy design, curtailment compensation, and system operator procurement rules. We show that DTU can increase welfare by inducing additional consumption when the marginal cost of electricity is low but retail prices do not reflect local system conditions, thereby improving allocative efficiency in transmission-constrained regions. These gains are invariant to whether curtailment is compensated, affecting only the distribution of surplus across agents.

1.2 Relevant literature

Our analysis relates to three strands of the literature: the declining value of variable renewable generation and the role of flexibility, the market design mechanisms underlying negative prices and curtailment, and the implications of these dynamics for renewable investment and policy design.

The first strand studies how the value of renewable generation changes as penetration increases. A central result is that the market value of variable renewables declines with deployment, as generation becomes increasingly concentrated in periods of low prices (Hirth, 2013). This effect reflects both temporal correlation in output and limited demand responsiveness in the short run. In such settings, system flexibility becomes a key determinant of efficiency, as it allows consumption or storage to shift toward periods of abundant supply.

A growing literature emphasizes that demand-side flexibility can partially offset value decline by absorbing surplus generation and reducing reliance on curtailment (Faruqui and Sergici, 2010; Borenstein, 2005). More recent work has emphasized that demand activation in electricity markets can be informed by analogous mechanisms used in other sectors to shift consumption across time, such as dynamic pricing and targeted incentives (Torriti, 2026). However, most existing evidence on demand responsiveness is based on observational data or stated-preference surveys, leaving uncertainty about how consumers respond to short-notice incentives under real system conditions.

A second strand examines the market design and operational drivers of negative prices and renewable curtailment. Curtailment typically refers to available generation that is not utilized due to economic or system constraints (O'Shaughnessy et al., 2021). Negative prices arise as an equilibrium outcome in wholesale electricity markets when supply is inflexible and demand is insufficiently responsive, particularly in the presence of transmission constraints and non-convex generation technologies (Wolak, 2011). Output-based support schemes can further amplify these dynamics by increasing generators' effective marginal revenue, leading them to continue producing even when wholesale prices are negative (Jacobsen and Schröder, 2013). Empirical work shows that curtailment is often driven by localized congestion and network constraints rather than system-wide excess supply, with a small number of nodes or regions accounting for a disproportionate share of curtailed energy (Maji et al., 2025; Frysztacki and Brown, 2020). System-level modeling studies similarly highlight the interaction between transmission limits, minimum generation requirements, inflexible baseload (such as nuclear), and renewable variability in generating periods of surplus and negative prices (Frew et al., 2019; Prol and Zilberman, 2023; Novan and Wang, 2024). These findings suggest that increasing demand during periods of surplus generation may provide an alternative to curtailment, although there is limited empirical evidence on the effectiveness of such interventions in practice.

A third strand considers the implications of these dynamics for renewable investment and policy design. While curtailment can be an efficient short-run response to system constraints, persistent low or negative prices can reduce revenues and weaken investment incentives in the absence of appropriate market design (Borenstein, 2012). Policymakers have responded by adapting support mechanisms, including exposing renewable generators more directly to wholesale prices and limiting payments during negative price periods. At the same time, private contracting arrangements such as power purchase agreements increasingly incorporate provisions to manage exposure to price volatility. These developments reflect a broader shift toward integrating renewable generation into market-based systems while preserving incentives for investment (Newbery et al., 2018; Davis et al., 2023).

Within this literature, relatively little work provides causal evidence on the effectiveness of demand-side interventions designed to absorb surplus generation. The closest related study is Yang et al. (2025), which uses survey data to elicit hypothetical willingness to shift consumption toward low-price periods. In contrast, we provide field-experimental evidence on realized consumer behavior during periods of excess supply, allowing direct comparison of demand activation to alternative mechanisms such as curtailment. A central uncertainty surrounding these programs is the degree to which consumers respond to short-notice requests to increase demand. In the absence of credible estimates of demand responsiveness, policymakers cannot reliably assess the cost-effectiveness of turn-up events relative to curtailment. By providing causal estimates of consumer response, our results inform both short-run operational decisions and broader market design. In the short run, they shed light on the extent to which surplus generation can be absorbed through demand activation rather than generation curtailment. In the medium run, they provide evidence on how consumers respond to dynamic price signals more generally, informing the potential effectiveness of real-time pricing and other mechanisms designed to improve retail price pass-through.

1.3 Policy background

In a frictionless benchmark economy, electricity would be generated and sold at marginal cost, and transmission would be unconstrained. Wholesale prices would equal the marginal cost of serving demand at each location, and electricity would flow to wherever it is valued most. In such a setting, supply and demand would clear efficiently at all times. Negative prices could arise if the short-run marginal cost of generation were effectively negative; for example, due to high shutdown and start-up costs that make it optimal for producers to accept temporary losses as part of an intertemporal optimization problem.

As noted in Section 1.2, several frictions move the system away from this benchmark and increase the likelihood of negative prices and/or the need for explicit payments by a system operator to generators to shut off. These include transmission constraints without locational marginal pricing, output-based subsidies, and retail pricing failing to pass through wholesale price variation to consumers.

Policymakers have a range of tools available to address periods of excess generation. In the long run, expanding transmission infrastructure can alleviate congestion by redistributing surplus electricity across regions (Gonzales et al., 2023; Hausman, 2025; Doshi, 2026). Greater interconnection reduces the likelihood that localized oversupply translates into sustained negative prices. This can be complemented by implementing locational marginal pricing, which sharpens price signals to better reflect location-specific marginal costs of supply. In the medium run, governments can reform market design and subsidy schemes that distort production incentives. In particular, reducing or restructuring output-based support can reduce incentives to generate even when wholesale prices are negative. At the same time, greater retail price pass-through via real-time pricing or other dynamic tariff designs can increase the responsiveness of demand to wholesale market conditions. Some jurisdictions, such as Australia, have pursued more targeted time-of-use pricing to shift consumption toward periods of high renewable output, even if such instruments are less granular than real-time pricing.

In the short run, system operators have traditionally relied on curtailment to restore balance during periods of excess supply. While effective in reducing supply in the short-run, curtailment can be costly and may weaken investment incentives for renewable generation in the long-run. More recently, policymakers and market actors have begun experimenting with "turn-up" flexibility events, which instead increase demand during surplus periods. Turn-up can complement national wholesale pricing by targeting local network constraints through DSO flexibility or constraint markets. Furthermore, if customers shift consumption away from periods dominated by fossil generation, this may generate additional emissions abatement benefits.

Great Britain: Great Britain's electricity market contains several institutional and structural features that contribute to the prevalence of negative pricing.[2] Rapid renewable deployment, combined with transmission constraints — particularly between generation-rich Scotland and demand centers in England — can lead to localized oversupply. Wholesale markets clear at a national price, while network constraints are managed through ancillary markets. A key market is the Balancing Mechanism, which *both* sets the national wholesale price by determining the relevant imbalance cost in each half-hour, *and* procures actions in response to transmission constraints. The absence of granular locational pricing means that national wholesale prices do not fully reflect local transmission constraints nor distribution network congestion, increasing reliance on operator intervention and/or raising the likelihood that prices fall below zero to restore balance.

The UK uses output-based support schemes as its main mechanism to support renewable build-out, including Contracts for Difference (CfDs) and the legacy Renewables Obligation. While these mechanisms are important for providing revenue certainty for investors, they also historically insulated generators from wholesale price risk and weakened incentives to curtail during periods of negative prices. Recent changes to the CfD contract terms implemented in Allocation Round 4, removed subsidy payments when the market reference price falls below £0/MWh, thereby reducing support during negative pricing events and aligning payments more closely with real-time market outcomes. Empirical evidence suggests that suspending payments during consecutive negative-price hours reduces curtailment, but a question remains about the optimal threshold for the number of hours (Steenberghe and Ovaere, 2025).

[2] The UK's main energy market is Great Britain, which is managed by the National Energy System Operator. Northern Ireland is part of the UK, but its electricity system is operated separately as part of the Single Electricity Market on the island of Ireland and is managed by the System Operator for Northern Ireland (SONI) in coordination with EirGrid.

Institutionally, Great Britain has been relatively proactive in using demand flexibility to manage these dynamics. National Energy System Operator (NESO) procures a range of balancing services, including frequency response, reserve, and constraint management, and has increasingly opened these markets to distributed energy resources. Distribution System Operators (DSOs), such as Northern Powergrid, are also moving toward more active network management through flexibility procurement at the distribution level. However, integration between wholesale markets, balancing mechanisms, and local flexibility services remains incomplete, and price signals at the retail level continue to lag behind system conditions.

Spain: Spain's electricity system also exhibits structural features that contribute to negative pricing. Rapid growth in solar generation has increased the frequency of surplus conditions. Limited interconnection capacity with the rest of Europe and localized congestion can exacerbate oversupply in certain regions. As in Great Britain, wholesale prices clear over the whole region[3] rather than reflecting granular network constraints, increasing reliance on operator intervention when congestion binds.

The surge in negative prices from 2024 onwards has been reflected in new stipulations in renewable subsidies and contracting frameworks. Spain's more recent auction-based remuneration schemes expose renewable generators more directly to market prices than earlier feed-in regimes. However, legacy output-linked support arrangements and certain contractual structures can continue to influence production incentives during low-price periods. In parallel, lenders and offtakers in power purchase agreements (PPAs) have introduced contractual provisions such as zero-price floors and limits on negative-price settlement.

Intuition for demand turn-up welfare impacts: A useful way to understand the economics of demand turn-up is to recognize that, in constrained systems, the effective marginal cost of electricity can differ across locations even when a single wholesale price is reported. In generation-rich regions facing transmission constraints, the local value of electricity may be substantially below the national price, and in some cases effectively negative once curtailment and cycling costs are taken into account. In these settings, the system operator may be willing to pay for additional demand. In some cases, demand

[3] Wholesale day-ahead electricity prices in Spain and Portugal are jointly determined through the Iberian market (MIBEL), operated by the market operator OMIE (Operador del Mercado Ibérico de Energía). The clearing price is uniform across the coupled Iberian bidding zone.

turn-up may even occur at a negative procurement cost – i.e., when retailers are willing to pay the system operator to access low-cost electricity in a constrained region.

The possibility of a negative procurement cost may appear counterintuitive. However, it reflects a setting in which electricity in the constrained region has a lower marginal value than in the national wholesale market. In this sense, DTU can be interpreted as facilitating trade between regions with different effective prices, even when a single national price is reported. Under curtailment, energy that could be consumed at positive value is instead discarded, even when consumers would be willing to use it at a price above its local marginal cost. By contrast, DTU allows consumption to adjust to these local conditions, generating gains from trade that can be shared across consumers, retailers, generators, and the system operator.

The welfare framework we develop formalizes this intuition and shows that the efficiency gains from DTU arise from this reallocation, rather than from the specific way in which curtailment costs or subsidy payments are accounted for. In our setting, DTU tends to be welfare-improving primarily when the procurement cost is close to zero or negative, so that the system both avoids curtailment costs and expands consumption at low marginal cost.

2 Experimental design and data

The design of this experiment was to test the effect of financial incentives on encouraging customers to increase electricity consumption. To understand this, we ran five events in Great Britain, and five events in Spain. Our primary outcome of interest was electricity consumption levels during “turn-up" event windows.

2.1 Sampling and eligibility into the natural field experiment

We implemented our natural field experiment using eligible customers of Octopus in Great Britain and Spain.[4] We used two slightly different sampling procedures across settings due to cross-country differences in operational constraints, available covariates, and customer populations.

[4] As of January 2nd, 2025, Octopus Energy was the largest domestic electricity supplier in Great Britain, serving 7.8 million customers. Spain, Octopus entered the market through the acquisition of the local supplier Umeme. As of the start of our trial, they served 400,000 domestic customers.

Great Britain: In Great Britain, we had access to a large pool of eligible customer accounts and a rich set of covariates. Our implementing partner provided a sampling frame of 484,683 customer accounts deemed eligible for the trial. Customers were eligible if they had opted in to marketing communications, were not enrolled in or previously contacted about similar campaigns, had a smart meter, and were not on a real-time tariff that was already responding to negative prices.

From this frame, we drew a nationally representative sample using stratified sampling based on: (i) property value terciles interacted with urban–rural classification, (ii) property type (house versus non-house), and (iii) terciles of annual electricity consumption. Crossing these dimensions yields 36 strata. We computed each stratum's population share and used proportional allocation to select 60,000 customers. Between sampling and trial launch, 1,606 customers exited Octopus Energy or otherwise became ineligible, leaving a final sample of 58,394 customers.

Spain: In Spain, we began with the full population of domestic Octopus Energy customers and applied eligibility filters specified by our implementing partner, yielding a pool of 60,438 customers. Given the smaller customer base, we did not employ stratified sampling and instead included all eligible customers. Additional details on eligibility criteria are provided in Appendix A.3.1.

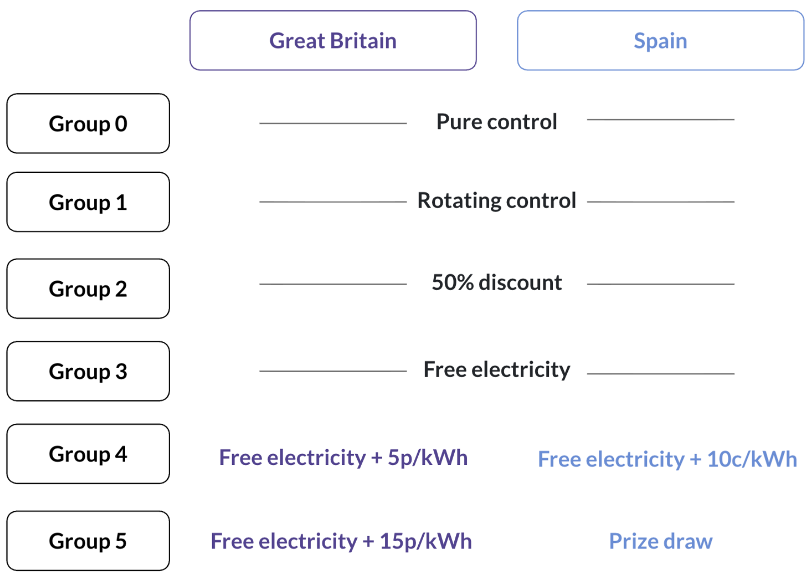
2.2 Treatment groups

In each country, for each event customers were randomized into five groups, as shown in Figure 2. Three groups were were common across countries: (1) a rotating control group, (2) a 50 percent discount on electricity consumption during the event and (2) free electricity consumption during the event.

The design of the negative pricing treatment arms differed slightly between the two countries. In Great Britain, there were two negative-price groups. In the first, customers received free electricity plus an additional payment of 5 pence per kWh consumed during the event window, equivalent to approximately 25% of the typical unit rate. In the second, customers received free electricity plus 15 pence per kWh, equivalent to approximately 75% of the typical unit rate. In Spain, the negative-price treatment consisted of free electricity plus a payment of 10 euro cents per kWh consumed during the event window, approximately 80% of the typical unit rate.

Additionally, Spain included a treatment arm where customers were offered free electricity for any consumption above their baseline level. In addition to receiving free electricity above baseline, ten participants were randomly selected to each receive a €150 prize. Eligibility for the prize draw required participation in the event, defined as increasing electricity consumption relative to baseline. The baseline was defined as consumption during the same hour over the previous ten days for weekdays and the previous three days for weekends.

Figure 2: Treatment design for Great Britain and Spain



2.3 Crossover randomization

In each country, we conducted five events and assigned customers to rotate through five treatment groups. In addition, a subset of customers was assigned to a pure control group and never received any treatment. To implement this rotation across events, we used two Latin squares, which generated 20 unique treatment sequences. Each sequence specified a distinct order in which a customer received the five conditions (four treatments and one rotating control), ensuring that (i) each customer experienced each condition exactly once over the five events and (ii) each condition appeared in each event position exactly once per Latin square, thereby controlling for order effects. We additionally included sequences in which customers were never treated, forming the pure control group. Examples of the crossover randomization sequences are shown in Figure 3.

Figure 3: Example of sequences in Great Britain crossover randomization

Randomisation	Event 1	Event 2	Event 3	Event 4	Event 5
Customer 1	Free + 5p	50% Discount	Free	Control	Free + 15p
Customer 2	Free	Free + 5p	Free + 15p	50% Discount	Control
Customer 3	Free + 15p	Control	Free	50% Discount	Free + 5p
Customer 4	Pure Control	Pure Control	Pure Control	Pure Control	Pure Control

We then employed matched pairs randomization to assign sampled households to these sequences, with the aim of ensuring pairwise treatment balance over time. The steps for how we conducted the matched pairs randomization are in Appendix A.3.2. In summary, though, for the Great Britain trial, we created blocks of 24 customers, randomly allocating 20 to each rotating-treatment sequence, and four to pure control "sequences". And, we created blocks of 26 customers for Spain – where, again 20 were randomly allocated to each rotating-treatment sequence, but *six* were allocated to pure control sequences. This randomization resulted in 9,710 customers in the pure control group and 48,684 customers assigned to treatment sequences in Great Britain. In Spain, 13,942 customers were randomized to the pure control group and 46,496 customers were assigned to treatment sequences.

Due to an implementation error, the fifth event in Spain inadvertently used the same treatment assignments as the fourth event. As a result, not all customers in Spain were exposed to all four treatments. However, the Latin square design ensured that every ordered pair of treatments appeared at least once as adjacent events across the treatment sequences. This property still held despite the duplication of treatment assignments in the final event.

Our design thus results in a within-customer (within-subject) randomized field experiment. Within-subject designs increase statistical power, but they require two assumptions additional to what is typically seen in a between-subjects setting to support causal interpretation. We go through these below.

First, there are three standard identification assumptions that would also be necessary with between-subject experimental designs (List, 2026). First, the Stable Unit Treatment Value Assumption (SUTVA) holds: a customer's potential outcomes do not depend on the treatment assignments of other customers. Second, observability is ensured through a balanced panel design: treatment was assigned only to customers for whom we reliably received smart meter data. While post-assignment attrition was possible, we tested for differential attrition and found no evidence that treatment affected outcome observability. Third, statistical independence holds, as treatment assignment was randomized and therefore independent of potential outcomes. Note that our analysis focused on intent-to-treat (ITT) effects rather than average treatment effects. While we observe email delivery, we cannot verify whether customers opened or read the treatment emails; full compliance is therefore not required for identification of the ITT estimate.

Adopting a within-subject design introduces an explicit time dimension, which necessitates two additional assumptions. The fourth assumption is temporal stability, which requires that time-varying factors affecting outcomes are not confounded with treatment assignment. We address this by randomizing the order of treatment conditions using a Latin square design, ensuring that all treatment conditions appear in each event. We further include event fixed effects to net out common time shocks from the estimated treatment effects. Finally, the design requires causal transience: treatment effects must not depend on prior or future treatments. This assumption rules out both anticipation and carryover effects. Anticipation is unlikely in our setting, as customers do not know when events will occur or what treatment they will receive. However, carryover effects may arise if treatment impacts persist over time.

We distinguish between two forms of carryover. The first is habit formation, where exposure to turn-up events could affect electricity consumption even during periods with no events. We test for habit formation by comparing customers assigned to the rotating control group to those in the pure control group. If the estimated coefficients for these two groups are statistically indistinguishable, this implies that any treatment effects are short-lived and do not persist beyond the event window. Conversely, statistically significant differences between these coefficients would indicate the presence of habit formation. As discussed in Section 3.1, we find that the coefficient estimates for the rotating and pure control groups are statistically indistinguishable, providing evidence that treatment effects do not persist beyond the event window.

The second form of carryover is learning, where responsiveness to treatment depends on prior exposure. Importantly, we view such learning as policy-relevant: our implementation reflects how turn-up events would plausibly be deployed in practice, and the Latin square design ensures that every ordered pair of treatments appears as adjacent events. This allows learning effects to be identified and interpreted as part of the treatment response rather than as a design flaw. We will explore these learning effects in subsequent analyses.

With these conditions satisfied, randomization identifies an internally valid and unbiased ITT estimate of the effect of turn-up events on household electricity consumption. Moreover, because customers were not required to opt in and therefore did not self-select into the experiment, we classify the study as a natural field experiment with unbiased treatment assignment.

2.4 Implementation of turn-up events

Turn-up events were conducted between June and September 2025. In Great Britain, each event lasted one hour, while in Spain each event lasted two hours. Events were not scheduled on predetermined dates. Instead, in coordination with the implementing partners, events were triggered when day-ahead wholesale electricity prices were close to zero or negative.

Three days prior to the first event, all sampled customers, except those assigned to the pure control group, received an informational email describing the nature of the turn-up events program and notifying them that events would occur during the study period, although the exact timing was not disclosed. Subsequently, 24 hours before each turn-up event, treated customers received a treatment-specific email informing them of the event timing and the associated financial incentive. Examples of the emails sent in Great Britain and Spain are shown in Figure A21 and Figure A22, respectively.

Remuneration for participation differed across countries. In Great Britain, remuneration was provided after all turn-up events had concluded. In Spain, customers were compensated on a rolling basis, typically one to two weeks after each event.

2.5 Experimental integrity

Balance: Table A1 reports baseline balance between treatment and control groups in Great Britain and Spain. Overall, observable characteristics were well balanced across groups in both countries. These results are consistent with successful randomization. The crossover design provides an additional safeguard against baseline imbalance. Because households cycle between treatment and control status across events, time-invariant characteristics are orthogonal to treatment assignment in specifications that use the rotating control as the reference group.

Attrition: Attrition is low in both samples and does not differ by treatment status. In Great Britain, 7 percent of households attrit, while in Spain the attrition rate is 8 percent. Attrition occurs only if a household leaves Octopus during the study period and we believe unrelated to our treatment. Regressions of attrition on treatment assignment yield small and statistically insignificant coefficients in both countries, indicating no evidence of differential attrition (Table A2).

Pre-analysis plan: This study was pre-registered through the AEA RCT Registry. The Great Britain trial was registered as AEARCTR-0016220, the Spain trial was registered as AEARCTR-0016221, and the NPG trial was registered as AEARCTR-0015455.

2.6 Empirical strategy

To estimate the Intention-to-treat (ITT) effect of turn-up events on hourly electricity consumption (kWh), we use the following specification:

$$Y_{it} = \alpha + \sum_{k=1}^{K} \beta_k E_{it}^{k} + \mu_b + \pi_1 C_{it} + \pi_2 K_{it} + \delta_t + \gamma X_i + \epsilon_{it} \tag{1}$$

where Y_{it} represents import electricity consumption (kWh) for consumer i during hour t.[5] E_{it} is an indicator variable equal to 1 if household i is assigned to treatment group k at time t, and 0 otherwise. μ_b is customer i's block. These blocks were formed for our matched-pairs randomization, as explained in Appendix A.3.1. C_{it} is customer's i average hourly consumption in the same hour over the last 5 working days before hour t. Analogously, K_{it} is for the last 2 weekend days. δ_t are hourly fixed effects, capturing common shocks or trends affecting all customers on a specific day. We cluster standard errors at the level of consumer i.

We additionally control for X_i, a vector of time invariant baseline customer characteristics, based on what is available in each country. In Great Britain, this vector includes (1) baseline estimated annual consumption (split into quartiles), (2) type of smart meter installed in the property, (3) Energy Performance Certificate (EPC) rating (categorical variable with 8 levels), and (4) tenure with Octopus Energy (in categories: 0-1 years, 1-2

[5] Our analysis used high-frequency administrative data on consumption from Octopus Energy Limited (Great Britain) and Octopus Energy España, S.L.U. (Spain). We pre-specified our main outcome variable as hourly electricity consumption during turn-up events (import only).

years, 2-3 years, 3-4 years, 4-5 years, more than 5 years). In Spain, this vector includes (1) baseline afternoon consumption, defined as the mean hourly consumption between 13:00 and 17:00 in May 2025 and (2) tenure with Octopus Energy (Octopus Energy Spain started in 2023, and thus the categories here are only 0-1 years, 1-2 years, 2-3 years).[6]

The β_k values are thus our coefficients of interest, as it measures the treatment effect of treatment group k, relative to the pooled control group.

3 Results

3.1 Main results: consumption during events

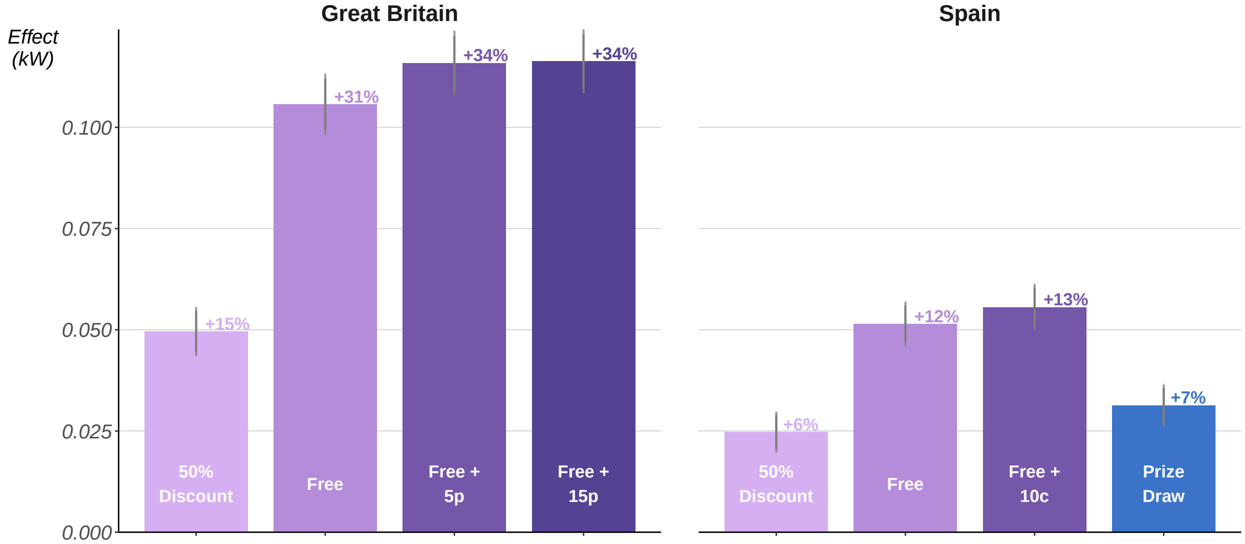
Across both countries, treatment effects are monotonically increasing and economically intuitive along the margin from no incentive to a 50% discount to free electricity, before exhibiting sharply diminishing returns to additional incentives (i.e., negative pricing). Figure 4 presents estimates from our main pre-registered specification in Equation (1). In Great Britain, customers offered a 50% discount increased hourly electricity consumption by 0.049 kWh, corresponding to a 14% increase relative to the control group. Offering free electricity roughly doubled this effect, to 0.105 kWh (31%). Adding a 5p/kWh payment on top of free electricity led to only a modest additional increase, to 0.115 kWh (34%), and increasing the payment to 15p/kWh did not yield a further meaningful increase (0.116 kWh, 34%).

Spain exhibits a similar qualitative pattern, though with smaller effect sizes. Customers offered a 50% discount increased hourly consumption by 0.024 kWh (7% relative to control), while offering free electricity again approximately doubled the effect to 0.051 kWh (13%). Adding a 10c/kWh payment on top of free electricity resulted in a small additional increase, to 0.054 kWh (13%). The prize draw produced an effect comparable in magnitude to the 50% discount, increasing consumption by 0.024 kWh (7%).

Table A3 and Table A4 present a set of alternative specifications used as robustness checks. Column (2) excludes both fixed effects and baseline controls. Column (3) includes

[6] We pre-specified that we would control for estimated annual consumption in Spain. However, this measure is not well defined for many customers because it is a modelled estimate from Octopus and can be quite noisy for new customers. Octopus Energy Spain has grown quickly over the past 10 years, so many customers are relatively new (average tenure 0.65 years in Spain compared to 4.03 years in Great Britain). This makes the estimated annual consumption measure much less reliable in Spain. Instead, we control for observed average baseline consumption between 13:00 and 17:00, which is directly measured rather than modelled. This is the variable we used for our matched sampling, as documented in our pre-analysis plan, and was chosen because this is the period during which Turn-up events were most likely to occur.

Figure 4: Treatment effects on hourly consumption (kWh)



Notes: This figure shows treatment effects from Table A3 and Table A4, our main pre-registered specification. Lines depict 90% (dark) and 95% (light) confidence intervals. Standard errors are clustered by customer. Our outcome measure is hourly consumption during the turn-up event. In Great Britain, events were one hour long, while in Spain, events were two hours long. Percentages represent average treatment effects as a share of the consumption in the control group during the event period.

customer fixed effects, absorbing all time-invariant individual-level heterogeneity and effectively using the rotating control group as the comparison group, rather than the pure control. Column (4) separates the rotating control group from the pure control group and restricts the comparison group to the pure control only. In Table A4, column (5) restricts the outcome to consumption in the first hour of the event window to assess whether treatment effects differ at the start of the event, a question that is particularly relevant when comparing to the British results given that the events in Great Britain lasted only one hour. Across all specifications, the estimated treatment effects are highly consistent in both magnitude and statistical significance.

Column (4) also serves as a test for habit formation, examining whether exposure to turn-up events affects electricity consumption even during periods when customers are not actively participating. The coefficient estimates on the rotating control group are small and statistically insignificant, suggesting that treatment effects are short-lived and do not persist beyond the event window.

The payment per induced kWh of turn-up is lowest when electricity is discounted or free (see Table 1). In contrast, paying customers to consume beyond zero price substantially increases total payments while generating only minimal additional demand.

Negative pricing for electricity use may nonetheless play a role in specific circumstances. If the objective is to procure a larger or more precisely targeted volume of demand, then higher incentives could be justified.

Table 1: Payment for each kWh of turn-up, by treatment group

Great Britain

Treatment	Total kWh (per event)	Total Payment (£)	£ per kWh
50% Discount	440.95	571.28	1.30
Free	953.09	1,156.97	1.21
Free + 5p	1,041.00	1,398.61	1.34
Free + 15p	1,045.85	1,842.03	1.76

Spain

Treatment	Total kWh (per event)	Total Payment (€)	€ per kWh
50% Discount	459.27	508.69	1.11
Free	949.21	1,056.89	1.11
Free + 10c	1,025.50	1,958.54	1.91
Prize Draw	577.85	1,837.68	3.18

Notes: The tables report the average total turn-up (in kWh) achieved by each treatment group per event, separately for each country. The payment per kWh is calculated as the total financial incentives paid to each treatment group divided by the total turn-up delivered by that group. For example, where customers would typically pay £0.28/kWh but were offered "free" electricity and consumed 0.5 kWh in the hour, the payment would be considered to be £0.14. The number of customers listed here is the number for the fifth event.

3.2 Heterogeneity

We examine heterogeneity in treatment effects by interacting treatment assignment with key baseline characteristics. Specifically, we consider three dimensions: (i) whether the customer was enrolled in a low-carbon-technology (LCT) specific tariff at baseline (applicable only in Great Britain, as EV and solar customers were excluded from the Spanish trial); (ii) whether the customer was on a time-of-use (ToU) tariff at baseline; and (iii) baseline estimated annual electricity consumption. These dimensions reflect differences in both experience with price-based incentives and access to flexible load. [7]

[7] Interactions with baseline tariff types were pre-specified. Interactions with baseline consumption were not pre-specified.

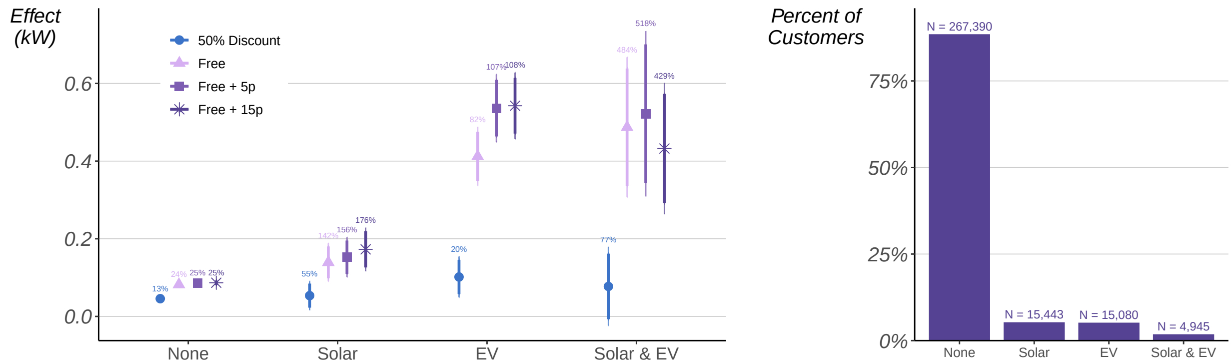
3.2.1 Heterogeneity by low-carbon technology (LCT) ownership

Ownership of low-carbon technologies (LCTs), such as electric vehicles and rooftop solar, represents access to large and flexible electric load. LCT status is therefore a central source of heterogeneity in turn-up responsiveness, particularly as electrification progresses and the prevalence of such technologies rises. As we do not directly observe LCT ownership, we proxied for it using customers' baseline tariff type. Octopus offers several LCT-specific tariffs, and we focus on those targeted to solar and electric vehicle (EV) customers, which have sufficient sample sizes to support statistical analysis. In Spain, however, solar and most EV customers were excluded from the trial because they were enrolled in other flexibility campaigns. As a result, we are able to examine heterogeneity by LCT status only in Great Britain.

Customers on LCT-specific tariffs exhibited substantially larger increases in consumption during turn-up events, as shown in Figure 5. In particular, customers on EV tariffs responded markedly more than those without EVs, consistent with EV charging providing a large and flexible margin of adjustment. The gradient was strongest for the Free and Free-plus-payment treatments.The relatively muted response among EV customers in the 50% discount group likely reflects the structure of prevailing EV tariffs. A 50% discount on the standard unit rate typically reduces the price to roughly 12 pence per kWh, which remains above the overnight EV charging rate of approximately 7 pence per kWh available on many dedicated EV tariffs. As a result, the discount does not meaningfully improve on customers' existing charging incentives, whereas free electricity represents a salient and economically dominant price signal. For example, under free electricity, customers with no LCT tariff increased demand by 0.08 kWh, customers with solar by 0.14 kWh, customers with EV tariffs by 0.42 kWh, and customers with both EV (electricity import) and solar (electricity export) tariffs by 0.51 kWh. These patterns indicate that access to flexible electrified load, rather than price exposure alone, drives much of the observed responsiveness.

In contrast, customers not on an LCT tariff exhibited smaller but still statistically significant responses, indicating that flexible demand was not confined to electrified households. Nevertheless, the magnitude differences suggest that as electrification progresses, the aggregate responsiveness to negative pricing events is likely to increase. These findings reinforce the complementarity between demand flexibility programs and broader decarbonization policies that promote LCT adoption.

Figure 5: Heterogeneity by LCT ownership, Great Britain



Notes: This figure shows how treatment effects vary by EV or solar ownership. Ownership is inferred from customers' baseline tariffs. Customers on an exporting tariff are classified as having solar, while customers on one of Octopus' EV tariffs (Octopus Go or Intelligent Octopus) are classified as having an EV. Lines depict 90% (dark) and 95% (light) confidence intervals. Standard errors are clustered at the customer level. The outcome measure is hourly electricity consumption during the event. The right hand side shows the share of customers with each ownership type.

3.2.2 Heterogeneity by baseline tariff type

Complementary to LCT-specific tariffs, we also examined heterogeneity by baseline time-of-use (TOU) status. On the one hand, TOU customers may exhibit more precisely timed demand shifts, reflecting greater familiarity with price variation and potentially access to routines or technologies that facilitate load adjustment. On the other hand, customers on fixed tariffs may display larger marginal responses if they have not previously optimized consumption in response to time-varying prices and therefore possess greater untapped flexibility.

In Great Britain, we distinguish between two types of TOU tariffs. "Classic TOUs" consist of traditional overnight tariffs (called Economy 7 and Economy 10) which provide a fixed number of off-peak hours, typically overnight, at a lower price. Economy 7 in particular was originally designed for households with electric storage heaters, which could absorb heat overnight at lower cost and release it during the day. "New TOU" include fixed multi-band tariffs with clearly defined peak and off-peak windows, dynamic pricing tariffs that track wholesale market conditions, and technology-specific tariffs linked to electric vehicle, heat pump, or solar and battery ownership. In Spain, by contrast, we distinguish between three types of tariffs: fixed tariffs; standard "TOU" tariffs where prices do not change day to day (following a regulated three-period structure common to many retailers in Spain); and "Dynamic TOU" tariffs, which are indexed to wholesale market prices.

As shown in Figure A3, TOU customers were more price responsive in both Great

Britain and Spain. In Great Britain, customers on Classic TOU tariffs exhibited larger treatment effects than those on fixed tariffs, while customers on New TOU tariffs displayed the strongest responses. Much of this gradient was driven by LCT-linked tariffs, consistent with the larger treatment effects documented in the previous section. The difference is particularly pronounced for the Free and Free-plus-payment treatments; we hypothesize this may be due to these treatments being lower than the TOU tariff's off-peak price per kWh, which in most cases is lower than the 50% reduction on the standard price per kWh. In Spain, TOU customers also responded more strongly than fixed-tariff customers, although the magnitude of the differential was smaller than in Great Britain.

3.2.3 Heterogeneity by baseline consumption

We also examined heterogeneity by baseline consumption in both countries. We defined baseline consumption as the average hourly consumption between 13:00 to 17:00 (local time) in May 2025. We divided customers into quartiles of baseline consumption and interacted these indicators with treatment assignment.

As shown in Figure A4a, in Great Britain, treatment effects increased monotonically with baseline consumption in absolute terms. Households in the highest consumption quartile exhibited substantially larger increases in electricity use during turn-up events than those in the lowest quartile, consistent with higher-consuming households having more adjustable load. Notably, however, the proportional response was highest for those in the lowest quartile, but lowest for those in the highest quartile. A similar, though more muted, pattern emerged in Spain. Higher-consumption households display larger absolute increases, while proportional responses decreased in baseline consumption (**??**). This suggests that while higher-consuming households shifted more electricity in level terms, lower-consuming households were more responsive relative to their baseline usage, potentially reflecting greater proportional flexibility or stronger price sensitivity among lower-consumption consumers.

3.2.4 Heterogeneity by geographic area

The expansion of renewables in Great Britain and Spain has been accompanied by geographic mismatches between where clean energy is produced and where it is consumed. In Great Britain, the highest concentrations of wind is in Scotland and northern regions, while major load centers such as London and the South East rely heavily on imports via the transmission system. A similar spatial tension exists in Spain, where renewable generation has grown rapidly, accounting for nearly 57% of total electricity production in 2024; yet much of this generation is located in rural or less densely populated regions, while demand is concentrated in large urban and industrial centers.

This spatial mismatch between renewable generation and consumption underscores the importance of understanding geographic heterogeneity in demand flexibility and the potential role localized demand response could play in balancing regional flows. Understanding whether responsiveness varies systematically across network regions is therefore central to assessing the operational value of localized demand-side flexibility.

In Great Britain, we studied heterogeneity across Grid Supply Point (GSP) Group. A GSP is a node at which electricity is transferred from the high-voltage transmission network to the lower-voltage distribution network. Each GSP Group aggregates multiple substations and represents a geographically coherent balancing area within the distribution system. These zones are frequently used in network planning and constraint analysis. In Spain, we examined heterogeneity across Comunidades Autónomas (Autonomous Communities), the primary administrative regions that also align reasonably well with spatial patterns in renewable deployment and demand concentration.

In Great Britain, the estimated hourly treatment effects were uniformly positive but varied meaningfully across GSP Groups and increased in dispersion as incentives strengthened, as shown in Figure A5a. Under the 50% Discount, effects ranged from roughly 0.03 to 0.09 kWh per hour, indicating modest yet consistent responsiveness across all regions. For the Free treatment, the range shifts upward to approximately 0.05 to 0.15 kWh per hour. Under Free + 5p, effects span about 0.06 to 0.17 kWh per hour, while the strongest incentive, Free + 15p, generated responses from roughly 0.06 to just above 0.20 kWh per hour. Notably, the largest effects were concentrated in Northern GSP groups, particularly Scotland, as illustrated in Figure A6a. This geographic pattern is encouraging from a system perspective, as these areas are also characterized by high renewable penetration and frequent constraint episodes.

Spain similarly exhibited positive treatment effects but meaningful dispersion, shown in Figure A5b. For the Prize Draw, estimated effects spanned approximately –0.03 to 0.08 kWh per hour. Under the 50% Discount, effects ranged from about 0.01 to 0.06 kWh per hour. The Free treatment produced a wider spread, roughly 0.01 to 0.08 kWh per hour, including one relatively large positive outlier. Finally, under Free + 10c, responses clustered between approximately –0.03 and 0.07 kWh per hour, with most regions concentrated in the positive 0.03–0.07 range. Overall, these patterns suggest that price elasticities differ across regions.

3.3 Difference between Great Britain and Spain

Consumers responded more strongly to incentives in Great Britain than in Spain, despite similar average customer rewards. In fact, in all cases of comparable incentives, the response was twice as strong in Great Britain as in Spain.

We do not have a definitive explanation for this cross-country difference, but we explored several contributing factors. First, differential engagement did not appear to be the driver. Email open rates were similar across countries: the average open rate was 65% in Spain and 62.4% in Great Britain, suggesting comparable exposure to the intervention.

Second, part of the difference reflected sample composition. In Spain, customers on a special EV tariff and most customers exporting solar were excluded from the trial, at the direction of the delivery partner, as they were enrolled in other flexibility campaigns. When we imposed a similar exclusion in Great Britain, removing customers on technology-specific tariffs, the gap narrowed. For example, under the Free treatment, the average increase in Great Britain was 0.115 kWh across all customers, but 0.082 kWh when restricting to non-LCT customers. The comparable effect in Spain was 0.049 kWh. Thus, differences in the prevalence of flexible electrified load explained part, though not all, of the observed gap.

Finally, event duration differed across countries. Events in Spain lasted two hours, whereas events in Great Britain lasted one hour. Although treatment effects in Spain remain similar when restricting the analysis to the first hour of the event (Table A4), longer event windows may mechanically dilute the estimated hourly response. For example, if running a washing machine requires approximately one hour, some customers may choose to operate it in the first hour of the event while others choose the second hour. As a result, demand may be distributed across the two-hour window rather than concentrated in a single hour. Consistent with this interpretation, the total increase in consumption across both hours in Spain is broadly comparable to the increase observed during the one-hour events in Great Britain.

3.4 Temporal demand substitution

While the primary objective of turn-up and negative pricing events is to absorb excess renewable supply, an additional question is whether these interventions generated net new demand or instead shifted consumption across time. If customers increased usage during the event window by reducing consumption in other periods, particularly during hours when wholesale prices were higher, this has two important implications. First, from the supplier's perspective, temporal substitution may lower procurement costs if demand is shifted away from high-price hours and into low- or negative-price hours; customers may also benefit if they are on a time-of-use tariff. Second, high-price periods typically coincide with when marginal generation is more carbon-intensive. Shifting consumption away from these hours could therefore reduce the emissions associated with electricity use.

To assess intertemporal substitution, we first estimate a two-way fixed effects event-study specification, examining treatment effects on hourly electricity consumption from 24 hours before to 72 hours after each event. As shown in Figure 6a and Figure 7a, we found some evidence of sustained elevated consumption in the hours immediately following events, but no notable reductions in consumption in the pre- or post-event windows more broadly.

However, any displacement may have been too diffuse across the surrounding hours to detect reliably in an event-study framework. We therefore conducted a complementary displacement analysis, aggregating consumption across four windows and regressing each on treatment assignment: (1) cumulative consumption in the 24 hours before the event, (2) consumption during the event window itself, (3) cumulative consumption in the 72 hours following the event, and (4) total consumption across the full −24 to +72 hour window. Event notification emails were typically sent approximately 24 hours before the event; we excluded any hours occurring before the notification was sent to avoid contaminating the pre-event window with periods during which customers could not yet have responded.

To improve statistical power, we pooled treatment groups with similar response profiles for this analysis. In Great Britain, we pooled the Free, Free + 5p, and Free + 15p groups, whose treatment effects were statistically indistinguishable in Table A3. In Spain, we pooled the Free and Free + 10c groups on the same basis (Table A4). We also report results from unpooled treatment groups.

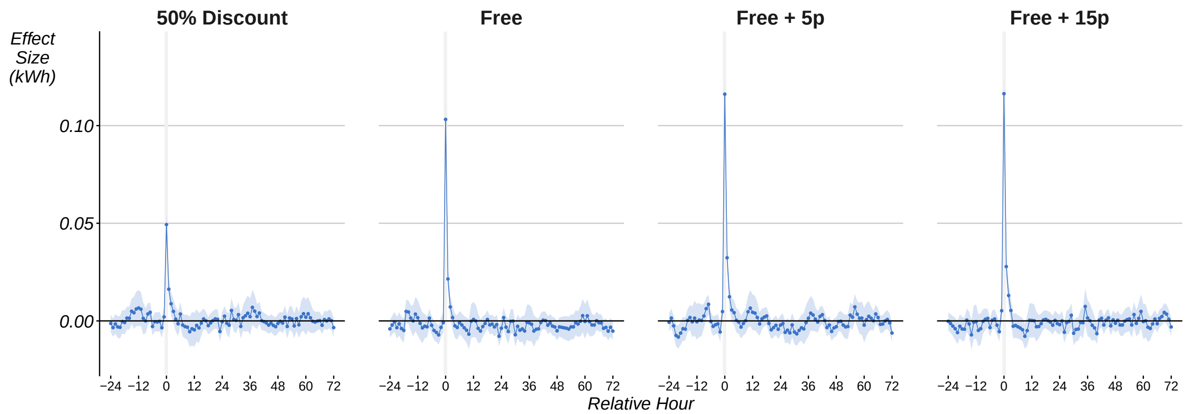
The results, shown in Figure 6b and Figure 7b, reveal a contrast between the two countries. In Great Britain, we found statistically significant evidence of intertemporal substitution: the pooled Free + Negative group showed a significant reduction in pre-event consumption, and the post-event window exhibited a cumulative downward pattern consistent with load shifting, together implying complete displacement of the during-event effect. In Spain, by contrast, cumulative effects remained close to zero in both the pre- and post-event windows, suggesting that the treatment effects in Spain reflected net increases in electricity consumption rather than demand shifted from adjacent periods. Looking at overall consumption from -24 to 72 hours, consumption increases by 0.091 kWh for the 50% discount group, 0.102 kWh for the Free group, and 0.115 kWh for the Free + 10c group, consistent with net demand creation.

We urge caution in interpreting displacement estimates for Great Britain. The 50% discount group in Great Britain and all groups in Spain showed no significant displacement, which we would expect if displacement were a systematic feature of customer behavior. The heterogeneity analyses also yielded no consistent evidence of displacement across subgroups (Figure A8, Figure A10, Figure A12). More fundamentally, intertemporal substitution is inherently difficult to quantify precisely: any displacement is likely to be diffuse across a long post-event window. We therefore interpret the evidence as consistent with some displacement in Great Britain, while remaining cautious about its precise magnitude.

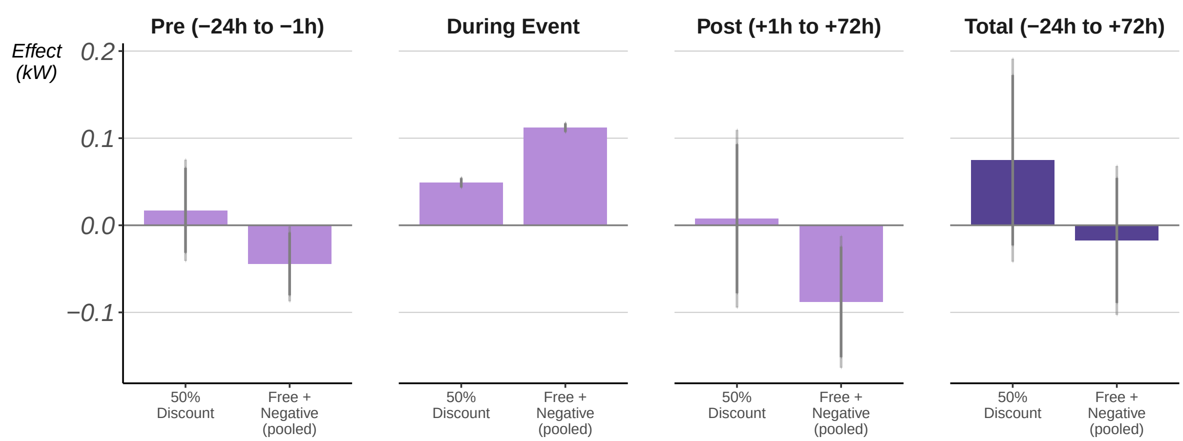
The source of this cross-country difference is not fully clear. One factor may be communication design: in Great Britain, event emails explicitly encouraged customers to shift consumption into the turn-up window, whereas the Spanish communications did not emphasize demand reallocation. A second, non-mutually exclusive explanation is that baseline consumption patterns and flexibility differed across the two contexts. If British households had more discretionary or shiftable loads, such as electric heating, hot water systems, or electric vehicles, they may have been better positioned to move demand across hours in response to price signals. By contrast, if a larger share of consumption in Spain was less temporally flexible, responses may have taken the form of incremental usage during the event window rather than substitution away from other periods. A third explanation concerns air conditioning, where the higher prevalence of air conditioning in Spain may have led to more net demand creation rather than displacement.

Figure 6: Effect of treatment, before and after event window - Great Britain

(a) Event Study



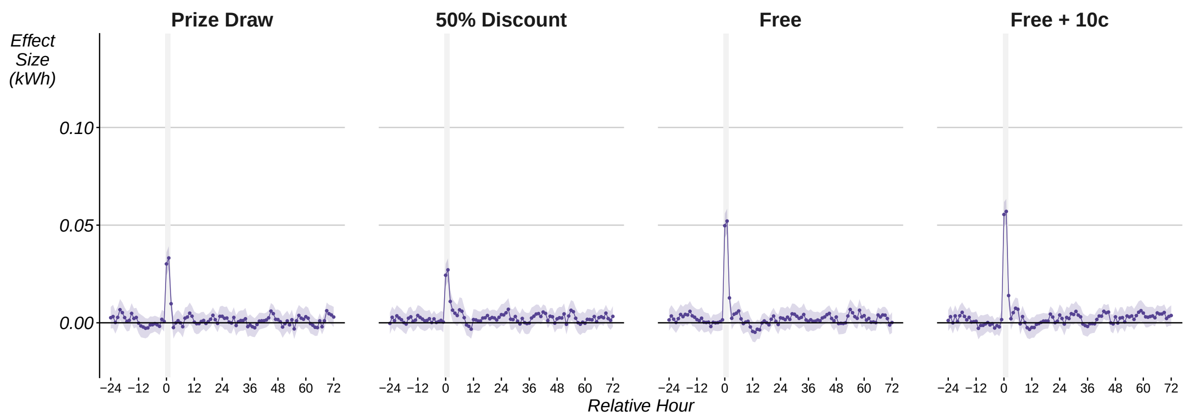
(b) Aggregate displacement



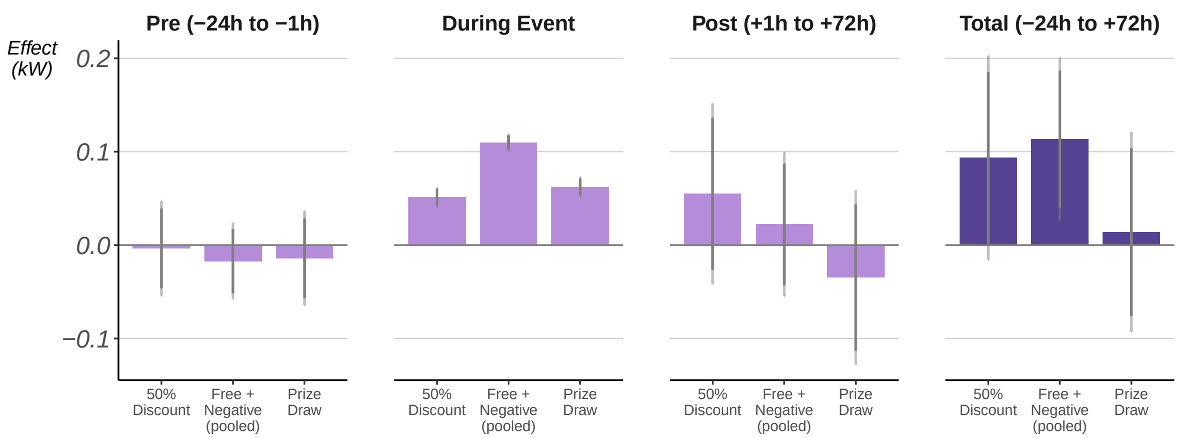
Notes: Panel a shows estimates from an event study analysis where we interact treatment with relative time since the event. Shaded regions are the 95% confidence interval. Panel b plots impact of treatment on cumulative electricity consumption in different windows. The first pane is from -24 hours to -1 hour before the event. The second pane is the hour during the event. The third pane is the total consumption during hours 1 to 72. The fourth pane is total consumption from -24 to +72 hours around the event. Shaded areas indicate 95% confidence intervals; standard errors are clustered at the customer level.

Figure 7: Effect of treatment, before and after event window - Spain

(a) Event Study



(b) Aggregate displacement



Notes: Panel a shows estimates from an event study analysis where we interact treatment with relative time since the event. Shaded regions are the 95% confidence interval. Panel b plots impact of treatment on cumulative electricity consumption in different windows. The first pane is from -24 hours to -1 hour before the event. The second pane is the hour during the event. The third pane is the total consumption during hours 1 to 72. The fourth pane is total consumption from -24 to +72 hours around the event. These coefficients represent treatment effects on cumulative pre-event consumption relative to the control group. Shaded areas indicate 95% confidence intervals; standard errors are clustered at the customer level.

4 Demand flexibility for locational network constraints: evidence from Northern Powergrid

The main turn-up experiments were triggered by national wholesale price conditions; events occurred when day-ahead prices were forecast to be near zero or negative across Great Britain and Spain. But the operational case for demand-side flexibility extends beyond national surplus management to localized network constraints, where renewable generation or network constraints creates binding bottlenecks at the distribution level. In Great Britain, these constraints are managed by Distribution Network Operators (DNOs), who must either curtail generation, invest in network reinforcement, or procure flexibility from consumers in the affected area.

Northern Powergrid (NPG), which serves around 3.9 million homes and businesses across the North East of England and Yorkshire, faces this challenge. Rapid growth in wind and solar in its network area has created recurring periods where local generation exceeds what the distribution network can accommodate. To test the extent to which domestic demand side response could help them solve these issues, NPG procured demand turn-up services from Octopus Energy Limited, the same energy retailer with whom we partnered on our larger British turn-up experiment. The retailer offered residential customers in two specific constrained GSP areas, Spennymoor and Ferrybridge B, free electricity during periods when NPG required increased demand to relieve local network pressure. Unlike the main experiment, events here were not triggered by wholesale prices, but by NPG's real-time assessment of distribution network constraints. This makes the NPG trial a direct test of whether residential demand flexibility could substitute for curtailment at the distribution level.

4.1 Study design and methodology

This trial used a crossover randomized control trial design to evaluate the impact of power-up events in the NPG region. We accessed a pool of 14,477 customers who had signed up to the program by the start of the trial on January 29th 2025, drawn from two network areas: 9,000 in Spennymoor and 5,477 in Ferrybridge B. Participation required customers to take action at two distinct stages. This opt-in structure distinguished the NPG trial from the main turn-up experiment in an important way: whereas turn-up participants were simply emailed informing them of an upcoming event and their assigned incentive, power-up customers first actively chose to enroll in the program before any events took place, and then separately opted in to each individual event when notified. The power-ups sample is therefore, by construction, more selected than the turn-up sample; participants had already demonstrated willingness to engage with demand flexibility before any event occurred.

NPG called turn-up events between January and March 2025 based on its operational assessment of network conditions, with neither the timing nor duration determined in advance. Over the trial period, there were 19 events across 15 event days, with some days featuring multiple events at different times of day. Because events on the same day share a common demand environment and because pre- and post-event windows would overlap for same-day events, we treat the event day as the unit of observation for our analysis.

For each event, customers were allocated to treatment (invited to participate) or control, with the allocation prioritizing customers who had received the fewest prior invitations, ensuring balance in treatment exposure over the trial. In Spennymoor, 2,400 customers were invited per event; in Ferrybridge B, 1,857. These invitation volumes were set based on expected turn-up and NPG's flexibility requirements in each area. Invited customers received an email notification, typically 24 hours in advance, and were required to confirm their participation by opting in to that specific event. The treatment was free electricity for the duration of the event window.

4.2 Empirical Specification

We estimate two specifications that reflect the double opt-in structure of the trial. Let Y_{it} denote electricity consumption for customer i at half-hour t. Our first specification estimates the reduced-form effect of being invited to a power-up event among customers already signed up to the program:

$$Y_{it} = \alpha + \beta^{SU}\text{SignedUp}_{it} + \gamma' X_i + \delta_t + \zeta_z + \varepsilon_{it} \tag{2}$$

where SignedUp_{it} is an indicator equal to one if customer i received an invitation to the event, X_i is a vector of baseline customer characteristics, δ_t are half-hour fixed effects, and ζ_z are zone fixed effects for Spennymoor and Ferrybridge B. The coefficient β^{SU} captures the intent-to-treat effect of invitation, conditional on prior programme enrollment.

Our second specification estimates the effect of actual event participation. Because opt-in to a specific event is potentially endogenous, we instrument for it using the invitation assignment, yielding a two-stage least squares estimator:

$$\text{OptIn}_{it} = \pi_0 + \pi_1 \text{SignedUp}_{it} + \gamma' X_i + \delta_t + \zeta_z + \nu_{it} \qquad \text{(First Stage)}$$

$$Y_{it} = \alpha + \beta^{EO} \widehat{\text{OptIn}}_{it} + \gamma' X_i + \delta_t + \zeta_z + \varepsilon_{it} \qquad \text{(Second Stage)}$$

where OptIn_{it} is an indicator equal to one if customer i opted in to the specific event. The coefficient β^{EO} captures the local average treatment effect of event participation for customers who opted in to an event when invited. Because participation requires action at two stages (program enrollment and event-specific opt-in), both layers of selection are embedded in this estimate. The gap between β^{EO} and β^{SU} therefore reflects event-level opt-in behavior conditional on prior program enrollment.

The baseline controls X_i match those used in the main turn-up regressions: average weekday and weekend half-hourly demand, meter type, EPC rating, and tenure with Octopus Energy. The outcome is measured at the half-hourly level, though for presentational clarity all regression tables report results aggregated to the hourly level. This specification differs from our pre-registered analysis plan; however, we adopt it here to ensure comparability across the turn-up and NPG trials. We report the pre-analysis plan specification as a robustness check.

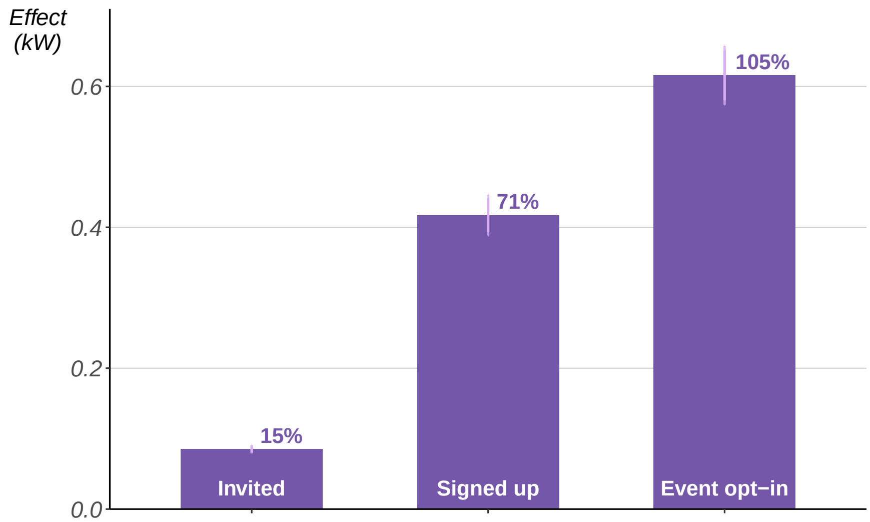
4.3 NPG Results

4.3.1 Main results: impact of NPG “power-up" events on event consumption

Consistent with the results from the Great Britain trial, free electricity substantially increased consumption during the event. Among those signed up to a power-up event, providing free electricity increased consumption by 0.417 kW on average among those signed up, rising to 0.616 kW for customers who opted into the event (Figure 8 and Table A7). Both estimates were statistically significant and robust across specifications, including models without covariates and two-way fixed effects models (Table A8). These translate to point elasticities of -0.714 for the signed up group, and -1.05 for the event opt-in group.

To make these estimates comparable to the Great Britain trial, we also present an

Figure 8: Effect of invitation, sign-up, and opt-in to NPG "power-up" events (kW)



Notes: This figure reports estimates of the effect of power-up events on half-hourly electricity consumption in the NPG region, reported at the hourly level for consistency with Table A3 and Table A4, the turn-up results. The first bar reports the estimated effect from the Free electricity group in the Great Britain trial, from Table A3 and Figure 4. The second bar reports the impact of being invited to power-up, among customers who signed up (Equation (2)). The third bar the impact of opting into the event, instrumented for by the encouragement (Equation (First Stage)). Baseline controls include average consumption at the same hour over the last 10 weekdays, average consumption at the same time over the last 2 weekends, meter type, EPC rating, estimated annual consumption, and tenure with Octopus Energy. The control mean refers to mean hourly consumption among uninvited customers during event half-hours. Standard errors are clustered at the customer level.

implied impact of being invited to participation. In the NPG trial, roughly 20% of contacted customers signed up, and those who signed up increased consumption by 0.417 kWh when invited. Scaling by the sign up rate gives an implied impact of being invited of 0.08 kWh per contacted customer. This is close in magnitude to the 0.1 kWh effect in the Free Electricity group observed in the GB trial, where no sign up was required and all customers were simply emailed. The smaller magnitude in the NPG case could reflect that sign-up still presents a friction, and potentially screens out customers who would have responded during an event, but did not engage with the enrollment process. However, we do not interpret the differences as causal, given substantive differences in implementation.

The opt-in design of the NPG trials has a clear advantage when looking at cost per kWh of turn-up procured. Whereas the free electricity events in the main Great Britain turn-up experiment cost £1.21 per kWh of additional demand elicited (Table 1), the NPG power-up events cost just £0.75 per kWh (Table A9). The higher cost in the Great Britain trial reflects the fact that, without an opt-in requirement, payments go to all invited customers including those who were unaware of the event or made no active change to their behavior. The active opt-in design of the NPG trial thus avoided these payments to nonresponding customers, delivering an average of 1.4 MWh of additional demand per event at substantially lower cost.

Heterogeneity in treatment effects by tariff type, shown in Figure A16, mirrors the pattern found in the main Great Britain turn-up experiment: customers on time-of-use tariffs and those with low-carbon technologies such as EVs and solar panels exhibit substantially larger responses, consistent with these customers having greater flexible load available to shift during event windows.

4.3.2 Dynamic consumption response: event study analysis

To examine how the consumption response evolved around events and how consumption evolved over differing treatment lengths, we estimated an TWFE specification. For each customer and each half-hour relative to the start of a given event, we estimated the interaction between treatment assignment and an indicator for each relative time period, including customer and half-hour fixed effects and clustering standard errors at the customer level. We focus on the 12 hours before and 12 hours after an event, and restricted this analysis to events where neither the 12 hours before nor the 12 hours after overlapped with another event; this left 11 events for analysis.

The event-study results confirm that the consumption response is sharply concentrated within event windows, as shown in Figure A17. Demand responses in the first two half-hours are similarly large across 30-minute, 1 hour, and 1.5 hour events. During 1.5-hour events, the response falls slightly in the third half-hour. For the longest event (4 hours), the per half-hour increase in consumption is smaller in magnitude but sustained throughout the event window, consistent with customers having a finite capacity to increase demand that becomes spread across a longer duration.

Across all event lengths, there is no evidence of anticipatory reductions in consumption in the hours before events. Displacement effects are also not apparent from the post-event coefficients. We suspect displacement is likely to be diffuse across the long pre- and post-event windows and therefore difficult to detect in an event-study framework. We return to this in the temporal demand substitution analysis in Section 4.3.3.

4.3.3 Temporal demand substitution

To further assess whether the consumption increases during events represented net demand creation or intertemporal substitution, we aggregated consumption across three windows: the 24 hours before an event, the event window itself, and the 72 hours following the event. Given the overlapping windows created by multiple events per day, we restricted this analysis to event days with no overlap, leaving 6 event days.

We found suggestive evidence of displacement, shown in **??**. The resulting coefficients before and after the event are noisy, leading to a noisy overall estimate of total consumption in the -24 to +72 hours that encompass the event. However, we suspect there may be displacement that was too diffuse to reliably detect. Taking the point estimates at face value, the net effect over the full window was positive, but about half the size of the effect during the event. This would be consistent with some intertemporal demand substitution, but overall net demand creation. The presence of some temporal substitution was also consistent with what we found in turn-up events in Great Britain (Section 3.4).

5 A partial welfare framework

This section develops a simple partial-equilibrium framework to characterize when demand turn-up (DTU) improves welfare. The goal is not to provide a full structural model, but to isolate the key forces determining (i) cost-effectiveness relative to curtailment and (ii) allocative efficiency in the presence of network constraints and imperfect retail price pass-through.

A key input into the framework is the estimated demand response from our field experiment. Across the 50 percent discount and free tariff treatments, we estimated a price elasticity of demand of approximately -0.3. This provides direct empirical evidence that households do respond to short-run price incentives, even in the absence of self-selection into participation in the program. In other words, observed DTU was not driven solely by compositional effects, but reflects a measurable average behavioral response at the population level. Heterogeneity analysis further suggests that this responsiveness is likely to increase with the diffusion of low-carbon technologies, as EV and heat pump owners exhibited significantly higher elasticities (see Section 3.2.1, and Figure A16).

Our results have implications for how one should think about pass-through of wholesale prices to retail customers, in general. Such pass-through of low wholesale prices increases consumer surplus directly. It may also improve overall system efficiency by reshaping demand in line with the system's generation and transmission cost profile, especially insofar as demand turn-up induces some substitution away from periods of relatively higher electricity scarcity (Borenstein, 2005). The relevance of this channel is likely to increase with ongoing structural changes in electricity systems. Rising penetration of variable renewable generation, increasing price volatility, and the diffusion of heat pumps and EVs all strengthen the role of short-run price responsiveness in system balancing.

Despite the importance of implicit wholesale price pass-through to retail prices, the policy implications are relatively clear: efficiency is maximized by markets that expose retailers to the locational and temporal marginal price of electricity, where retailers pass through these pricing variations to customers. For these reasons, the remainder of this section focuses instead on a more complex case: explicit system operator calls for demand turn-up in a constrained region with surplus generation, such as a generation-rich area facing transmission limits. In this setting, additional demand can be procured locally through balancing actions, while the national wholesale price remains unchanged. As a result, DTU operates as a localized intervention that increases consumption where the marginal cost of supply is low.

An additional motivation for focusing on transmission-constrained surplus regions is empirical. A growing body of evidence suggests that a substantial share of renewable curtailment is driven by local network congestion and constraints rather than economy-wide periods of low wholesale prices. In particular, recent system-level analyses find that congestion-related constraints account for the majority of curtailed energy in several high-renewables systems, with curtailment concentrated in specific nodes or transmission corridors rather than being uniformly distributed across time (Frysztacki and Brown, 2020; Maji et al., 2025). Consistent with this, recent evidence for California shows that a large fraction of curtailed renewable generation can be traced to transmission bottlenecks rather than system-wide oversupply conditions (Perry et al., 2026). This suggests that, in practice, curtailment is often a spatially localized phenomenon arising from network constraints, rather than purely a temporal pricing outcome driven by low aggregate demand. For this reason, the framework below focuses on a representative transmission-constrained region with surplus generation.

5.1 Cost effectiveness

We compare DTU and curtailment in terms of total system cost, including subsidy payments and balancing actions. Suppose a renewable generator is curtailed during a period of excess supply. Under output-based support schemes, such as Contracts for Difference (CfDs), in Great Britain and many other countries with similar market designs, curtailment requires compensating the generator for lost revenue. If the wholesale price is below the strike price, this compensation includes the foregone CfD top-up. In addition, curtailment may impose a small maintenance or cycling cost on the generator.

As a simple illustration, suppose the wholesale price is £20/MWh and the generator has a strike price of £100/MWh. Curtailment then requires compensating approximately £80/MWh in foregone subsidy, plus a maintenance risk premium (e.g., £3/MWh), for a total cost of roughly £83/MWh. Under DTU, the system operator instead procures additional demand. If demand can be induced at a price of £15/MWh, generation is not curtailed and the CfD top-up is paid. The total cost in this case is therefore £95/MWh, exceeding the cost of curtailment. However, if demand can be procured at a sufficiently low price, the ranking reverses. For example, if the system operator can procure demand at –£15/MWh (i.e., the retailer pays for the energy), the total cost falls to £65/MWh, which is below the curtailment cost.

The possibility of a negative procurement cost may appear counterintuitive. However, it reflects a setting in which electricity in the constrained region has a lower marginal value than in the national wholesale market. In this sense, DTU can be interpreted as facilitating trade between regions with different effective prices, even when a single national price is reported.

This comparison highlights that the cost-effectiveness of DTU depends on the price at which additional demand can be procured relative to the cost of constraint-down actions. Institutional features such as the Balancing Mechanism in Great Britain *in principle* allow for localized procurement of energy, effectively enabling retailers to access lower-priced electricity in constrained regions even when wholesale prices are set nationally. As we discuss in Section 5.4, in practice there are large barriers to entry for retailers to use the Balancing Mechanism in this way, and no such mechanisms for retailers to use balancing markets in Spain in this fashion.

Two additional considerations can modify this comparison. First, as we showed in both of our experiments in Great Britain – the nationwide trial (Table A6 and the trial with NPG (??) – DTU may induce demand shifting across hours. Increased consumption during low-cost periods may substitute for consumption during higher-cost periods, reducing procurement costs for retailers. This cost reduction should, in theory, allow retailers to accept higher costs of DTU, given that the DTU will cause savings on procurement in other hours. This implies that the relevant cost of DTU is not the contemporaneous payment for additional demand, but the net change in procurement costs across all hours.

Second, constraint-down payments may reflect, in part, strategic bidding by generators. There is evidence of some strategic bidding. Examining all British system-operator-accepted constraint-down bids between 19 February 2025 and 18 February 2026, the median mark-up was 17% (Figure A20). This is defined as the extent to which total curtailment revenue exceeds a counterfactual baseline based on CfD top-up payments. Some of this mark-up does reflects a premium to cover cycling and maintenance risks associated with curtailment, but the size of the wedge suggests additional profit.[8] There are also notable upward outliers, which may reflect the exercise of market power in particular areas of Great Britain. Insofar as constraint-down bids exceed the foregone revenue from output-based subsidies, DTU may become more cost-effective. In a sense, DTU is a way of reducing the market power of generators whose constraint-down bids far exceed their marginal cost of curtailment. While this channel reflects imperfections in bidding behavior rather than a fundamental efficiency advantage of DTU, it is nevertheless relevant in practice.

5.2 Stylized partial equilibrium framework

Consider a representative short-run market period with baseline demand Q_0 and inverse demand $P(Q)$, where $P'(Q) < 0$. Let $c \approx 0$ denote the marginal cost of renewable generation.

Total surplus is given by

$$W = \int_0^Q P(q)\,dq - cQ - C^{sys}, \tag{3}$$

where C^{sys} denotes system-level adjustment costs associated with balancing excess gen-

[8] Discussions with Octopus Energy Generation suggest that wind generator cycling and maintenance risks are on the order of £3/MWh, which is only approximately 6% of the median counterfactual CfD top-up revenue (£50.28) in our analysis of bids between 19 February 2025 and 18 February 2026.

eration or inducing additional demand.

Curtailment regime. Under curtailment, excess generation is reduced one-for-one when supply exceeds demand, so that no additional demand is created. System costs arise from foregone payments and operational inefficiencies:

$$C^{curt} = (\tau + \kappa\tau)\max\{Q_0 - Q, 0\}, \tag{4}$$

where τ is the foregone subsidy payment per unit (e.g., CfD top-up) and $\kappa \geq 0$ captures additional costs from cycling, bidding frictions, and operational wear. The term τ is interpreted as a pure per-unit transfer associated with renewable generation that is independent of whether output is curtailed or absorbed through induced demand.

Realized welfare is therefore

$$W^{curt} = \int_0^{Q_0} P(q)\,dq - cQ_0 - C^{curt}. \tag{5}$$

Demand turn-up (DTU). Under DTU, excess generation is absorbed through additional demand induced at price p. Let $Q^{DTU}(p)$ denote induced demand with $Q_p^{DTU} < 0$. System costs reflect both remuneration of induced demand and foregone subsidy payments:

$$C^{DTU}(p) = (p + \tau)\,Q^{DTU}(p). \tag{6}$$

Realised welfare is

$$W^{DTU}(p) = \int_0^{Q^{DTU}(p)} P(q)\,dq - cQ^{DTU}(p) - C^{DTU}(p). \tag{7}$$

Key observation (regime comparison). Define welfare under each regime as above.

Proposition 5.2.1. *Welfare comparisons are invariant to compensation incidence: the difference $W^{DTU}(p) - W^{curt}$ depends only on real resource costs and demand responses, and not on whether τ is paid by consumers, generators, or the state.*

Proposition 5.2.2. *DTU can be welfare improving relative to curtailment. There exist prices p such that $W^{DTU}(p) > W^{curt}$.*

Corollary 1. *Institutional features such as curtailment compensation rules or CfD pass-through* *affect distributional incidence but do not affect efficiency rankings across regimes.*

In Section 5.3, we interpret these two regimes – curtailment versus DTU – in terms of supply-side and demand-side efficiency margins.

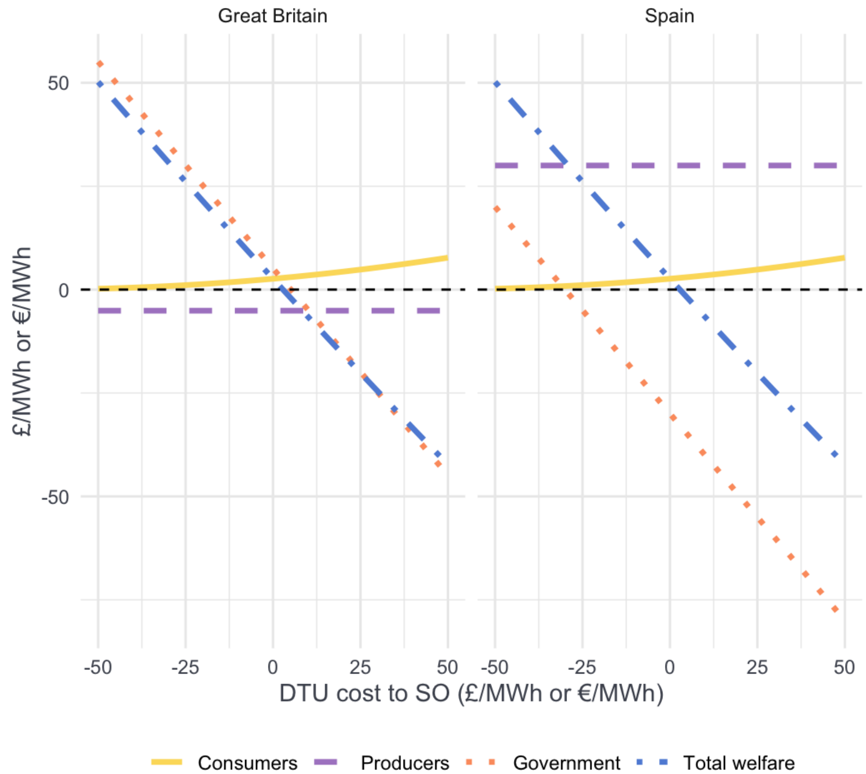
5.3 Welfare considerations and allocative efficiency

In principle, the allocation of curtailment across generators is not a primary source of short-run inefficiency when dispatch reflects marginal system costs and transmission constraints are properly internalized in prices (Hogan, 1992; Newbery et al., 2018; Joskow, 2008). Under these conditions, whether curtailment is compensated or not does not affect the set of units that are efficiently curtailed, and therefore primarily affects distributional incidence and investment incentives rather than operational efficiency. This supply-side invariance is consistent with the Coase theorem (Coase, 1960), in the sense that different allocations of property rights over curtailment rents do not affect efficient short-run allocation under frictionless pricing. In the framework of Section 5.2, curtailment operates solely on the baseline quantity Q_0, consistent with the invariance result in Proposition Proposition 5.2.1, in the sense that compensation rules do not alter the underlying allocation of production.

While supply-side allocation is largely efficiency-neutral under the maintained assumptions of the model, demand-side distortions may still arise when retail prices do not reflect local or temporal variation in system marginal costs. In particular, when wholesale prices are spatially uniform and do not internalize network constraints, consumers in regions with abundant renewable generation may face prices that exceed the local marginal cost of supplying energy. This can lead to inefficiently low consumption in periods where additional demand would be welfare improving.

Demand turn-up (DTU) can be interpreted as a corrective mechanism for this distortion, as illustrated in Figure 9. By inducing additional consumption in periods and locations where the marginal cost of supply is low, DTU generates real welfare gains that arise from improved alignment between marginal consumption value and system marginal cost, rather than from accounting reclassification of system costs. As formalized in Proposition 5.2.2, this adjustment in quantities is what generates potential welfare gains relative to curtailment, by allowing consumption to respond to marginal system conditions rather than remaining fixed at Q_0. These gains are distinct from the distributional effects of curtailment compensation regimes. While compensation rules affect

Figure 9: Welfare decomposition under dynamic turn-up (Great Britain vs Spain)



Notes: This figure reports a stylized welfare decomposition under demand turn-up (DTU) for Great Britain and Spain. Each panel shows net government savings, consumer surplus, producer surplus, and total welfare as a function of the DTU cost to the system operator (SO). The comparison isolates institutional differences in curtailment compensation. In Great Britain, curtailed generation is compensated; empirically, we found that generators demanded a median of 117% of their counterfactual contract-for-difference (CfD) top-up revenue, implying that curtailment carries an explicit fiscal cost through replacement of subsidy payments (plus a 17% mark-up). In Spain, curtailed generation does not receive compensation, so curtailment does not generate an equivalent fiscal transfer. All behavioral parameters, including demand elasticity, baseline prices, and demand response functions, are held constant across countries. Welfare is defined as the sum of consumer surplus, producer surplus, and net government savings. We include the system operator and subsidy payments within the government sector. Differences between Great Britain and Spain therefore reflect institutional accounting rather than differences in underlying consumption preferences or demand behavior. DTU generates net government savings at lower retailer payments to the system operator in jurisdictions like Great Britain, where curtailment requires compensation to generators. Under these assumptions, total welfare is identical across countries for a given underlying system cost; differences in the figure reflect institutional accounting of DTU payments and curtailment costs rather than real resource effects. For simplicity, the figure assumes a wholesale cost of £70/MWh (€70/MWh), an output-based subsidy (e.g., a CfD top-up) of £30/MWh (€30/MWh), and a retail price of £240/MWh (€240/MWh).

fiscal flows between generators, consumers, and system operators, they do not directly affect the efficiency condition governing whether energy is curtailed or reallocated through demand response, provided that compensation is a pure transfer and does not distort dispatch or consumption decisions (Corollary 1).

5.4 Comparison across institutional settings

The cost-effectiveness of demand turn-up (DTU) depends on the institutional treatment of curtailment when viewed through system accounting costs. In systems where curtailment is compensated, such as Great Britain, DTU can reduce net system costs if the price required to induce additional demand is sufficiently low relative to avoided constraint-down payments. In contrast, in systems where curtailment is not compensated, such as under technical curtailment regimes in Spain, the system operator can reduce output without incurring direct fiscal transfers to generators. As a result, curtailment may appear costless from an accounting perspective, even though it still reflects foregone opportunities for consumption.

To build intuition for the welfare mechanism in Section 5.2, consider a simple thought experiment that abstracts from institutional accounting and focuses on the underlying gains-from-trade logic underlying Proposition 5.2.1. Suppose a renewable generator would lose a €50/MWh output-based payment if curtailed. In the absence of transaction costs, the generator would therefore be willing to pay up to €50/MWh to avoid curtailment and continue producing. At the same time, consumers (or retailers acting on their behalf) derive positive value from additional electricity consumption during periods of surplus generation.

In this setting, there exists a range of mutually beneficial trades that are not realized under curtailment. For example, if consumers are willing to pay €15/MWh for additional consumption, then there is up to €65/MWh of potential surplus from reallocating energy from curtailment to consumption. This surplus can in principle be shared between generators, consumers, and the system operator, and therefore does not depend on how payments are distributed across agents. The key point is that curtailment fixes allocation on the supply side and prevents demand from adjusting, so these gains from trade are not realized even when they are jointly feasible. This implies that curtailment can be inefficient even when it appears costless in system accounts, because the relevant distortion is not fiscal incidence but the failure to enable mutually beneficial reallocation of energy when marginal system costs are low.

In practice, these theoretical gains are constrained by limited demand-side participation in balancing markets. In Great Britain, participation of demand in the Balancing Mechanism (BM) faces a combination of institutional and operational constraints. First, the timing of the BM poses challenges for demand-side response. Gate closure occurs one hour ahead of delivery, leaving limited time to notify consumers and induce additional consumption. This is particularly restrictive for residential demand, where responses are not fully automated. Participation has also historically required relatively stringent metering and verification arrangements. Although these requirements have been relaxed in recent years, they continue to impose frictions that are less binding for large generators than for distributed demand-side resources.

As a result, even if DTU is welfare improving in principle, the realized gains may be substantially smaller in practice, and in some cases negligible relative to the theoretical potential. More broadly, these frictions suggest that reforms aimed at improving access for demand-side resources, for example through longer notification windows and more flexible metering requirements, could increase the effectiveness of DTU as a system-balancing tool.

The constraints are, if anything, more binding in systems such as Spain. When curtailment is implemented administratively and without compensation, there is no clear or systematic mechanism through which demand-side resources can bid to absorb excess supply. In Great Britain, the challenge is primarily one of access: demand-side resources face barriers to participating in an existing balancing framework. In Spain, the challenge is more fundamental: the absence of a comparable mechanism for demand-side participation during curtailment events limits the scope for DTU to operate at all.

An important qualification to the preceding analysis is that it abstracts from dynamic behavioral and investment responses to the allocation of curtailment risk. In particular, the assumption that curtailment does not affect generator behavior is more plausible in the short run than in the long run. Borenstein (2012) and Newbery et al. (2018) emphasize that the distribution of price and quantity risk in electricity markets can materially affect investment incentives, technology choice, and locational decisions, even when short-run dispatch remains efficient. Exposing generators more directly to curtailment risk may improve locational efficiency and encourage co-location with storage or flexible demand. These effects operate through investment and strategic responses rather than short-run dispatch, and are therefore not captured by the static welfare framework developed above. As a result, the net welfare comparison between alternative curtailment regimes is theoretically ambiguous once these dynamic considerations are taken into account, and remains an open empirical question.

5.5 Generalizability across market designs

The welfare properties of demand turn-up (DTU) can be understood more generally through differences in how electricity systems assign and price the right to use constrained transmission capacity. In practice, market designs vary along a small number of dimensions that determine whether congestion is reflected in prices, whether curtailment is compensated, and whether demand responds to local scarcity conditions.

At one end of the spectrum are systems in which curtailment is implemented administratively and generators do not hold a firm financial claim over foregone output. In these settings, which resemble the Spanish case, redispatch decisions do not typically involve direct compensation payments. DTU in such environments is therefore unlikely to generate fiscal savings relative to curtailment, since the system operator does not incur substantial marginal costs from reducing output. Nevertheless, DTU can still improve allocative efficiency by increasing consumption in periods where the marginal cost of electricity is low but retail prices remain positive.

A second class of systems, exemplified by Great Britain, retains administrative curtailment but combines it with explicit compensation for curtailed generation, where generators bid to be constrained down, and generators that would have received an output-based subsidy generally demand to be *paid* to be constrained down. In these environments, curtailment has a direct fiscal cost, since generators must be compensated for foregone revenues. DTU can therefore substitute for curtailment and reduce system costs when demand can be procured at sufficiently low prices. However, these gains are mediated by institutional constraints on demand-side participation in balancing markets and the need for explicit activation of demand response.

At the other extreme are systems with locational marginal pricing, in which network constraints are directly embedded in prices. In such settings, scarcity and congestion are reflected through spatial price variation, and negative prices can emerge endogenously in surplus regions. Demand responds directly to these price signals, so that DTU-like adjustments occur through market prices rather than administrative intervention. From this perspective, LMP represents a benchmark in which many of the distortions that DTU seeks to address are already internalised, and the scope for additional welfare gains from explicit DTU policies is correspondingly limited.

We believe system-operator called DTU will be most relevant in the first two environments. In both cases, DTU operates as a second-best mechanism that partially restores efficient consumption. However, its application may be limited by barriers to entry, and these barriers may be greater in the first system type, where generators are not compensated for curtailment. In systems with locational marginal pricing, we would expect DTU to occur without the need for explicit ancillary markets for system operation and balancing.

A final consideration for all three market types is the extent to which non-wholesale energy costs are loaded into retail prices. As highlighted by Borenstein and Bushnell (2015, 2022), retail electricity prices commonly include substantial non-wholesale components, including volumetric charges used to recover policy costs and network expenditures. These features dampen the pass-through of wholesale price variation to final consumers. Reducing the share of non-energy costs in retail prices would increase the extent to which wholesale conditions are reflected in retail tariffs. In a related way, this reduction would increase the proportional price decrease that retailers could offer when they are able to procure energy at below-wholesale prices during DTU events. Indeed, the price reductions used in our experimental treatments — i.e., 50% and 100% discounts — were large relative to those that would typically be feasible under current retail pricing structures, even if retailers were able to procure DTU through balancing markets. However, such price variation becomes increasingly feasible as non-energy costs are removed from marginal retail electricity prices, bringing retail tariffs closer to underlying wholesale costs.[9]

6 Conclusion

This study provides the first large-scale, cross-country field experimental evidence on consumer responsiveness to time-bound electricity price *reductions* and negative pricing in the context of increasing renewable penetration. We randomized 120,000 households across Great Britain and Spain into varying financial incentives, finding that residential demand was elastic when prices fell toward zero. However, we identified a "zero-price" threshold: 50% and 100% price decreases were associated with price elasticity of demand of -0.3, while the marginal gains from further payments ("negative" pricing) were minimal. While we found evidence of intertemporal shifting in Great Britain, in Spain our results suggested net demand creation.

[9] Partly with this in mind, the UK Department for Energy Security and Net Zero (2026) recently announced a levy exemption on DTU on a trial basis.

The results highlight a complementarity between demand-side flexibility and the broader electrification of the economy. Households equipped with low-carbon technologies, particularly electric vehicles, exhibited elasticities four to five times greater than traditional households. This suggests that technical potential for demand turn-up to balance intermittent renewable supply may grow as the global vehicle fleet and heating systems transition to electricity. Our findings indicate that demand turn-up is possible without any sign-up or opt-in selection on the part of customers, as demonstrated by our main trials; however, responsiveness and cost-effectiveness both increase by introducing a sign-up stage to select for more engaged customers.

From a system operation perspective, demand turn-up offers a partial alternative to curtailment as a mechanism for managing surplus renewable generation. Rather than relying solely on supply-side reductions, system operators can leverage short-run demand responses to help manage periods of congestion and excess generation. Our results also indicate that the effectiveness of this tool depends on the composition of the demand side and the presence of flexible electrified loads, implying that its value will evolve alongside ongoing changes in system design and electrification.

From a welfare perspective, demand turn-up offers an improvement over traditional curtailment by addressing the allocative inefficiency associated with retail prices remaining high due to fixed levies and limited pass-through even during periods of low marginal costs of generation. By aligning consumption with these periods of surplus, system operators can reduce the fiscal burden of compensating curtailed generators while providing direct value to consumers. The welfare gains remain the same even in systems where system operators can technically curtail generators without compensating them, but the gains from demand turn-up in those systems may be distributed differently.

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A Appendix

A.1 Tables

Table A1: Balance Table

Variable	Control Mean	Treatment	N
A. Great Britain			
Octopus tenure	4.02	0.01	60,951
	[1.79]	(0.02)	
Estimated annual consumption (kWh)	3961.92	-3.79	60,951
	[3272.33]	(9.05)	
Energy rating	4.23	-0.01	60,951
	[0.79]	(0.01)	
TOU tariff	0.20	-0.00	59,398
	[0.40]	(0.00)	
Joint F-Test		0.35	
B. Spain			
Octopus tenure	0.65	0.01	64,579
	[0.59]	(0.01)	
Baseline afternoon consumption (kW)	0.64	0.00	60,462
	[0.51]	(0.00)	
TOU tariff	0.28	-0.00	64,575
	[0.45]	(0.00)	
Joint F-Test		0.38	

Note: This table reports baseline balance between households assigned to treatment and pure-control households, separately for Great Britain (Panel A) and Spain (Panel B). For each covariate, the *Control Mean* column reports the mean in the pure-control group; standard deviations are in brackets. The *Treatment* column reports the coefficient on an indicator for treatment assignment from a separate OLS regression of the covariate on treatment status with randomization-block fixed effects; standard errors are in parentheses. *N* is the number of non-missing observations used in each row-specific regression. The *Joint F-Test* row reports the p-value from a test that all listed covariates are jointly unrelated to treatment assignment within panel. Estimated Annual Consumption is measured in kWh. Current energy rating is based on the official A–G efficiency scale and is mapped to a numerical value for analysis. TOU tariff is an indicator for enrollment in a time-of-use tariff. Baseline afternoon consumption is the mean hourly consumption between 13:00 and 17:00 in May 2025, before the start of the trial.

Table A2: Attrition

Sample	Mean Attrition (Treated)	Mean Attrition (Pure Control)	Difference	p-value
Great Britain	0.068	0.069	-0.002	0.565
Spain	0.080	0.078	0.002	0.347

Notes: This table reports attrition rates for treated and pure control customers in Great Britain and Spain. Attrition is defined as leaving Octopus Energy during the study period. The difference column reports the coefficient from a regression of attrition on treatment assignment with randomization-block fixed effects. P-values are from a test of the null hypothesis that attrition rates are equal across groups.

Table A3: Great Britain Robustness, impact of treatment on hourly consumption (kWh)

	Main	kWh Control	No Controls	Customer FE	Pure Control
Model:	(1)	(2)	(3)	(4)	(5)
Variables					
50% Discount	0.049***	0.050***	0.050***	0.046***	0.051***
	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)
Free	0.105***	0.106***	0.105***	0.101***	0.107***
	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)
Free + 5p	0.115***	0.116***	0.116***	0.112***	0.117***
	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)
Free + 15p	0.115***	0.116***	0.117***	0.113***	0.117***
	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)
Rotating Control					0.004
					(0.003)
Fixed-effects					
Covariates	Yes	Yes	No	Yes	Yes
Hour	Yes	Yes		Yes	Yes
Block	Yes	Yes		Yes	Yes
Customer				Yes	
Fit statistics					
Control Mean	0.34	0.34	0.34	0.34	0.337
Observations	271,058	271,058	271,366	271,239	271,058

Clustered (Customer) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

Note: This table reports ITT estimates of the effect of one hour turn-up events on electricity consumption during the event in Great Britain. Column (1) is our main pre-registered specification; (2) excludes fixed effects and baseline controls; (3) includes customer fixed effects; (4) separates the rotating control group from the pure control group, restricting the comparison group to the pure control group only. Standard errors are clustered by customer.

Table A4: Spain Robustness, impact of treatment on hourly consumption (kW)

Model:	Main (1)	PAP Controls (2)	No Controls (3)	Customer FE (4)	Pooled Control (5)	Reweighted (6)	First Hour (7)
Variables							
Prize Draw	0.031***	0.031***	0.032***	0.033***	0.030***	0.023***	0.030***
	(0.003)	(0.003)	(0.003)	(0.004)	(0.003)	(0.002)	(0.003)
50% Discount	0.025***	0.026***	0.027***	0.025***	0.024***	0.018***	0.023***
	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.002)	(0.003)
Free	0.051***	0.053***	0.054***	0.053***	0.051***	0.041***	0.050***
	(0.003)	(0.003)	(0.004)	(0.004)	(0.003)	(0.003)	(0.003)
Free + 10c	0.056***	0.056***	0.058***	0.059***	0.055***	0.042***	0.055***
	(0.003)	(0.003)	(0.004)	(0.004)	(0.003)	(0.003)	(0.003)
Rotating Control					-0.002		
					(0.003)		
Fixed-effects							
Covariates	Yes	Yes	No	Yes	Yes	Yes	Yes
Hour	Yes	Yes		Yes	Yes	Yes	Yes
Block	Yes	Yes		Yes	Yes	Yes	Yes
Customer				Yes			
Fit statistics							
Control Mean	0.418	0.418	0.418	0.418	0.418	0.26	0.413
Observations	563,470	542,831	600,740	600,640	563,470	563,462	281,795

Clustered (Customer) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

Note: This table reports ITT estimates of the effect of two hour turn-up events on hourly electricity consumption during the event in Spain. Column (1) is our main pre-registered specification; (2) excludes fixed effects and baseline controls; (3) includes customer fixed effects; (4) separates the rotating control group from the pure control group, restricting the comparison group to the pure control group only; (5) restricts the outcome to the consumption in the first hour of the event window. Standard errors are clustered by customer.

Table A5: Impact of treatment on hourly consumption (kW), no solar / EV

Model:	GB (1)	GB, No solar/EV (2)	Spain (3)
Variables			
50% Discount	0.05***	0.04***	0.03***
	(0.003)	(0.003)	(0.003)
Free	0.11***	0.08***	0.05***
	(0.004)	(0.003)	(0.003)
Free + 5p	0.12***	0.09***	
	(0.004)	(0.003)	
Free + 15p	0.12***	0.09***	
	(0.004)	(0.003)	
Prize Draw			0.03***
			(0.003)
Free + 10c			0.06***
			(0.003)
Fit statistics			
Control Mean	0.34	0.341	0.418
Observations	271,058	245,913	542,831

*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

Note: This table reports regression estimates of the impact of treatment on hourly electricity consumption (kWh) during turn-up events. Column (1) presents results for the full Great Britain sample, column (2) restricts the Great Britain sample to households without electric vehicles or solar, and column (3) reports results for Spain. All specifications follow the main empirical model and include the same set of controls and fixed effects as in the baseline results.

Table A6: Impact of treatment on aggregate consumption, -24 to +72 hours

Country	Great Britain		Spain	
Model	Separate Treatments	Pooled Treatment	Separate Treatments	Pooled Treatment
Model:	(1)	(2)	(3)	(4)
Variables				
50% Discount	0.079	0.079	0.091*	0.091*
	(0.060)	(0.060)	(0.055)	(0.055)
Free	-0.098*		0.102*	
	(0.059)		(0.055)	
Free + 5p	0.010			
	(0.060)			
Free + 15p	0.059			
	(0.058)			
Free + Negative (pooled)		-0.009		0.109**
		(0.044)		(0.044)
Prize Draw			-0.007	-0.007
			(0.054)	(0.054)
Free + 10c			0.115**	
			(0.054)	
Fixed-effects				
Event	Yes	Yes	Yes	Yes
Block	Yes	Yes	Yes	Yes
Fit statistics				
Observations	270,662	270,662	278,409	278,409

*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

Note: This table reports regression estimates of the impact of promotional treatments on aggregate consumption within a window of 24 to +72 hours around treatment exposure. Columns (1)–(2) present results for Great Britain, and columns (3)–(4) for Spain. "Separate treatments" specifications estimate each intervention individually, while "pooled treatment" specifications combine selected treatments as indicated. All models include event and block fixed effects. The estimates in (2) and (4) correspond to the average treatment effects visualized in Figure 6 and Figure 7 in the main text.

Table A7: Effect of invite and opt-in to NPG “power-up" events (kW)

	Signed up			Event opt-in		
Region	Pooled	Ferrybridge B	Spennymoor GSP	Pooled	Ferrybridge B	Spennymoor GSP
Model:	(1)	(2)	(3)	(4)	(5)	(6)
Variables						
Encouraged	0.417***	0.658***	0.254***			
	(0.015)	(0.030)	(0.013)			
Opted In (IV)				0.616***	0.893***	0.398***
				(0.021)	(0.040)	(0.020)
Controls						
Covariates	Yes	Yes	Yes	Yes	Yes	Yes
Half-Hour	Yes	Yes	Yes	Yes	Yes	Yes
Zone	Yes	Yes	Yes	Yes	Yes	Yes
Fit statistics						
Control Mean	0.584	0.605	0.574	0.584	0.605	0.574
Observations	234,631	85,459	149,172	234,631	85,459	149,172
Wald (1st stage), Opted In				21,292.6	11,884.5	10,468.3

Clustered (Customer) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

Note: This table reports estimates of the effect of power-up events on half-hourly electricity consumption in the NPG region, reported at the hourly level for consistency with Table A3 and Table A4, the turn-up results. Column (1) reports the impact of being invited to turn-up across both network areas, amongst customers who signed up. Column (2) restricts the estimate to Ferrybridge B. Column (3) restricts the estimate to Spennymoor. Column (4) reports the impact of opting into the event, instrumented for by the encouragement, across both network areas. Column (5) restricts the estimate to Ferrybridge B. Column (6) restricts estimate to Spennymoor. All specifications include baseline controls and half-hour and zone fixed effects. Baseline controls include average consumption at the same hour over the last 10 weekdays, average consumption at the same time over the last 2 weekends, meter type, EPC rating, estimated annual consumption, and tenure with Octopus Energy. The control mean refers to mean hourly consumption among uninvited customers during event half-hours. Standard errors are clustered at the customer level.

Table A8: Robustness: Effect of invite and opt-in to NPG “power-up" events (kW)

	Signed up			Event opt-in		
Specification	PAP	No Controls	TWFE	PAP	No Controls	TWFE
Model:	(1)	(2)	(3)	(4)	(5)	(6)
Variables						
Encouraged	0.411***	0.417***	0.435***			
	(0.015)	(0.013)	(0.012)			
Opted In (IV)				0.607***	0.610***	0.640***
				(0.021)	(0.018)	(0.017)
Controls						
Covariates	Yes	No	No	Yes	No	No
Half-Hour	Yes	Yes	Yes	Yes	Yes	Yes
Zone	Yes	Yes	Yes	Yes	Yes	Yes
Customer			Yes			Yes
Fit statistics						
Control Mean	0.584	0.584	0.584	0.584	0.584	0.584
Observations	234,800	338,218	338,217	234,800	338,218	338,217
Wald (1st stage), Opted In				21,321.7	31,915.5	35,409.7

Clustered (Customer) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

Note: This table reports robustness checks for the estimates in Table A7. Column (1) reports the impact of being invited to turn-up using the pre-analysis plan specification. Column (2) reports the estimate excluding baseline controls. Column (3) reports the estimate using a two-way fixed effects specification, additionally including customer fixed effects. Column (4) reports the impact of opting into the event, instrumented for by the encouragement, using the pre-analysis plan specification. Column (5) reports the estimate excluding baseline controls. Column (6) reports the estimate using a two-way fixed effects specification, additionally including customer fixed effects. All specifications include half-hour and zone fixed effects. Baseline controls in columns (1) and (4) include average consumption at the same hour over the last 10 weekdays, average consumption at the same time over the last 2 weekends, meter type, EPC rating, estimated annual consumption, and tenure with Octopus Energy. The control mean refers to mean hourly consumption among uninvited customers during event half-hours. Standard errors are clustered at the customer level.

Table A9: Cost of turn-up, NPG

Event Date	Event Length (hours)	Total Payment (£)	Estimated Turn-up (kWh)	Number of opt-ins	Payment per kWh of Turn-up (£)
A. Total					
Total		15,897.48	21,113.66	19,836	0.75
B. Ferrybridge					
01 Feb, 2025	5	3,476.68	4,740.23	1,367	0.73
08 Feb, 2025	1	842.25	1,161.82	1,298	0.72
15 Feb, 2025	1	904.45	1,441.70	1,185	0.63
19 Feb, 2025	1	704.21	942.89	1,165	0.75
26 Feb, 2025	1.5	1,097.10	1,641.42	1,153	0.67
27 Feb, 2025	1.5	1,175.45	2,121.70	1,069	0.55
28 Feb, 2025	1.5	1,106.60	1,774.17	1,164	0.62
C. Spennymoor					
30 Jan, 2025	0.5	471.03	563.08	1,705	0.84
31 Jan, 2025	0.5	489.05	692.81	1,678	0.71
05 Feb, 2025	4	1,430.43	2,255.48	1,437	0.63
12 Feb, 2025	1.5	439.49	379.62	1,259	1.16
18 Feb, 2025	3	1,527.58	964.17	1,334	1.58
25 Feb, 2025	2	525.07	299.98	1,057	1.75
04 Mar, 2025	1	875.20	1,057.53	1,475	0.83
11 Mar, 2025	1	832.88	1,077.06	1,490	0.77

Notes: The tables report the total payment and turn-up achieved by customers who opt-ed into each event in the NPG trial. The cost per kWh is calculated as the total financial incentives paid divided by the total turn-up delivered.

Table A10: Great Britain, impact of treatment on climate sentiment

Model:	(1)	(2)	(3)	(4)	(5)
Variables					
Treated	-0.006	0.008	-0.016	0.015	-0.033
	(0.025)	(0.043)	(0.041)	(0.041)	(0.039)
Octopus Sentiment	0.433^{***}	0.298^{***}	0.489^{***}	0.487^{***}	0.455^{***}
	(0.013)	(0.022)	(0.019)	(0.020)	(0.020)
Fixed-effects					
Block ID	Yes	Yes	Yes	Yes	Yes
Fit statistics					
Observations	4,261	4,261	4,261	4,261	4,261

Clustered (Block ID) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

Note: This table reports estimates of the impact of exposure to turn-up events on climate-related sentiment among participants in Great Britain. The dependent variables are responses to post-experiment survey questions, measured on a five-point Likert scale, where higher values indicate more positive views toward energy flexibility, renewable energy, and climate policy. "Treated" is an indicator equal to one if a customer received any turn-up communications, and zero if assigned to the pure control group. "Octopus Sentiment" controls for respondents' stated alignment with Octopus Energy's mission, to account for potential response bias. All specifications include matched-pair block fixed effects.

Table A11: Spain, impact of treatment on climate sentiment

Model:	(1)	(2)	(3)	(4)	(5)
Variables					
Treated	-0.009	0.003	-0.013	0.004	-0.028
	(0.020)	(0.034)	(0.033)	(0.034)	(0.034)
Octopus Sentiment	0.425***	0.390***	0.476***	0.434***	0.400***
	(0.010)	(0.017)	(0.016)	(0.016)	(0.017)
Fixed-effects					
Block ID	Yes	Yes	Yes	Yes	Yes
Fit statistics					
Observations	5,532	5,533	5,533	5,533	5,532

Clustered (Block ID) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

Note: This table reports estimates of the impact of exposure to turn-up events on climate-related sentiment among Spanish participants. The dependent variables are responses to post-experiment survey questions, measured on a five-point Likert scale, where higher values indicate more positive views toward energy flexibility, renewable energy, and climate policy. "Treated" is an indicator equal to one if a customer received any turn-up communications, and zero if assigned to the pure control group. "Octopus Sentiment" controls for respondents' stated alignment with Octopus Energy's mission, to account for potential response bias. All specifications include matched-pair block fixed effects.

A.2 Figures

Figure A1: Hourly electricity consumption (kW), Great Britain

graphs/desc_hourly_gb.pdf

Notes: This figure plots mean hourly electricity consumption (kWh) by treatment group for each of the five turn-up events in Great Britain. Each panel corresponds to one event day. The shaded grey band indicates the one-hour event window.

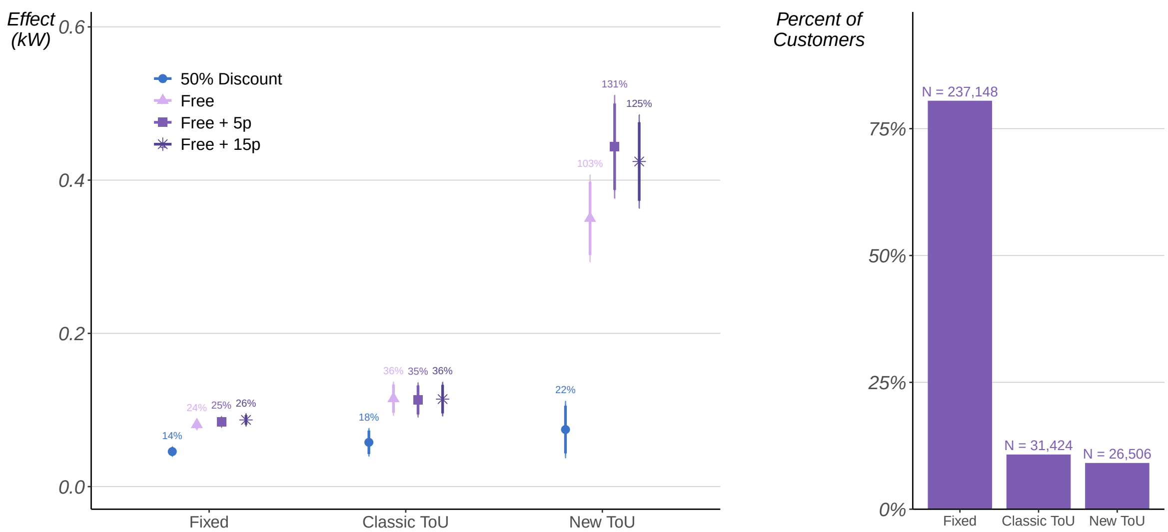
Figure A2: Hourly electricity consumption (kW), Spain

graphs/desc_hourly_spain.pdf

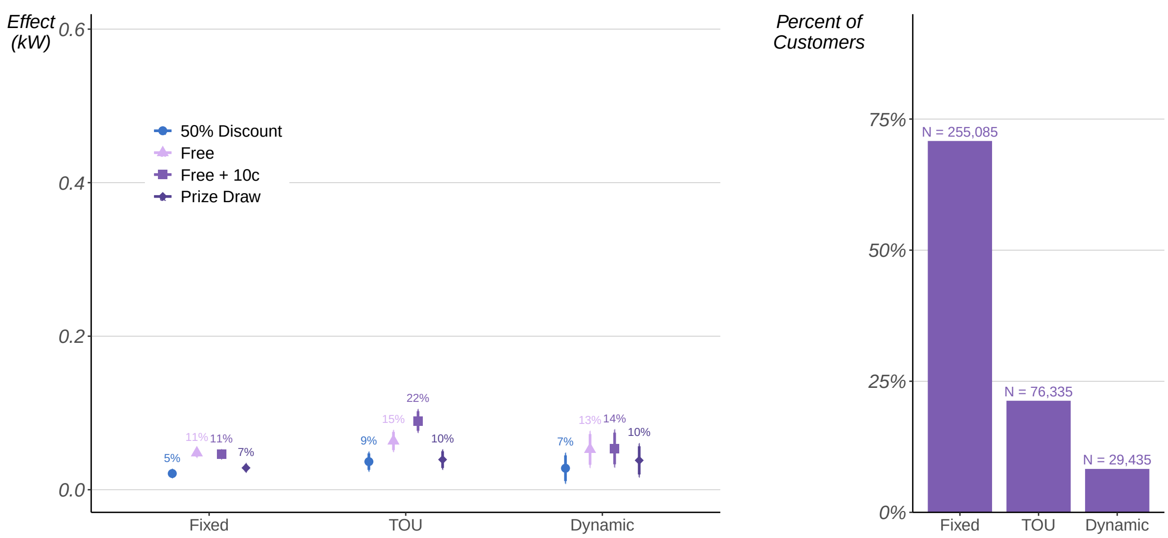
Notes: This figure plots raw mean hourly electricity consumption (kWh) by treatment group for each of the five turn-up events in Spain. Each panel corresponds to one event day. The shaded grey band indicates the two-hour event window.

Figure A3: Heterogeneity, by baseline tariff

(a) Great Britain



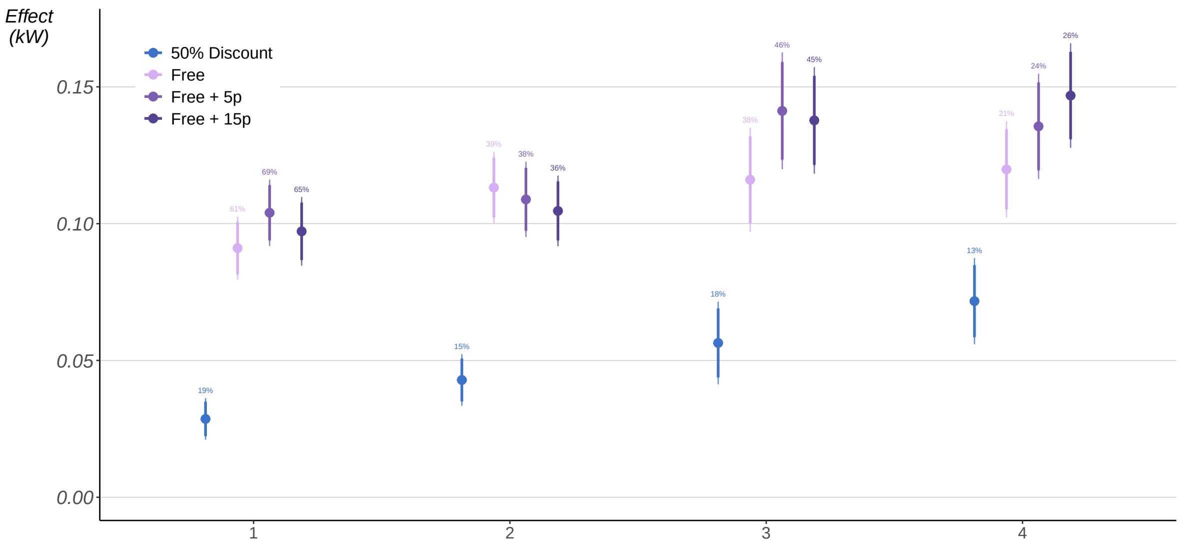
(b) Spain



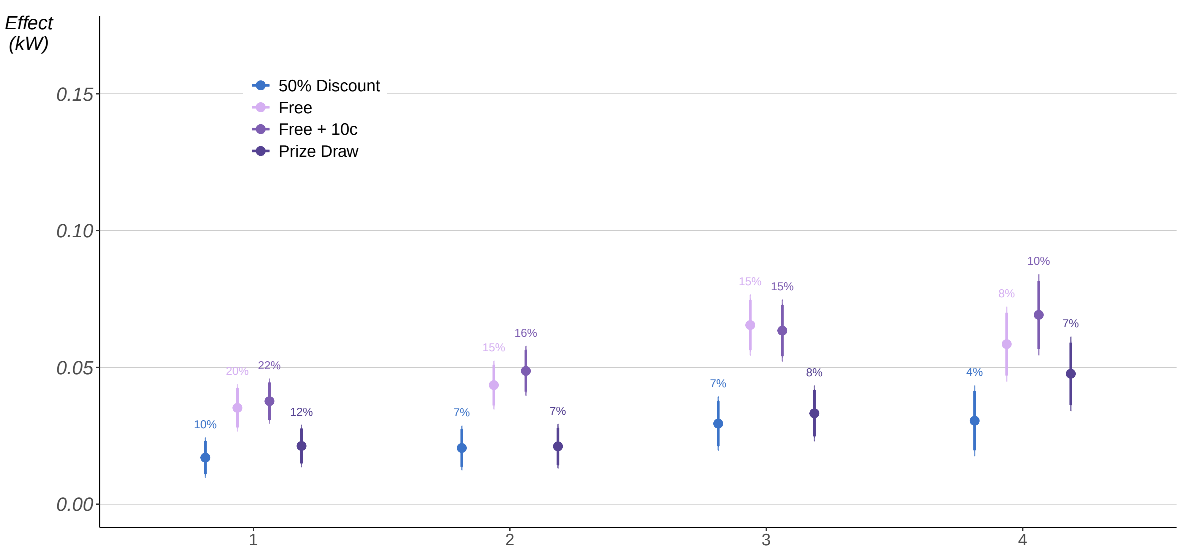
Notes: This figure shows how treatment effects vary by baseline tariff. Figure A3a presents results for Great Britain. The left-hand side plots treatment effect estimates by baseline tariff category: Fixed, Classic TOUs which consist of traditional overnight tariffs (ToU), and New TOU which include fixed multi-band tariffs with clearly defined peak and off-peak windows as well as rela-time pricing tariffs that track wholesale market conditions. The right-hand side shows the share of customers in each baseline tariff category. Figure A3b presents results for Spain. We differentiate between Fixed, TOU tariffs where prices do not change day to day, and Dynamic TOU tariffs which are indexed to wholesale market prices. Lines depict 90% (dark) and 95% (light) confidence intervals. Standard errors are clustered at the customer level. The outcome measure is hourly electricity consumption during the event.

Figure A4: Heterogeneity by estimated annual consumption quartiles

(a) Great Britain



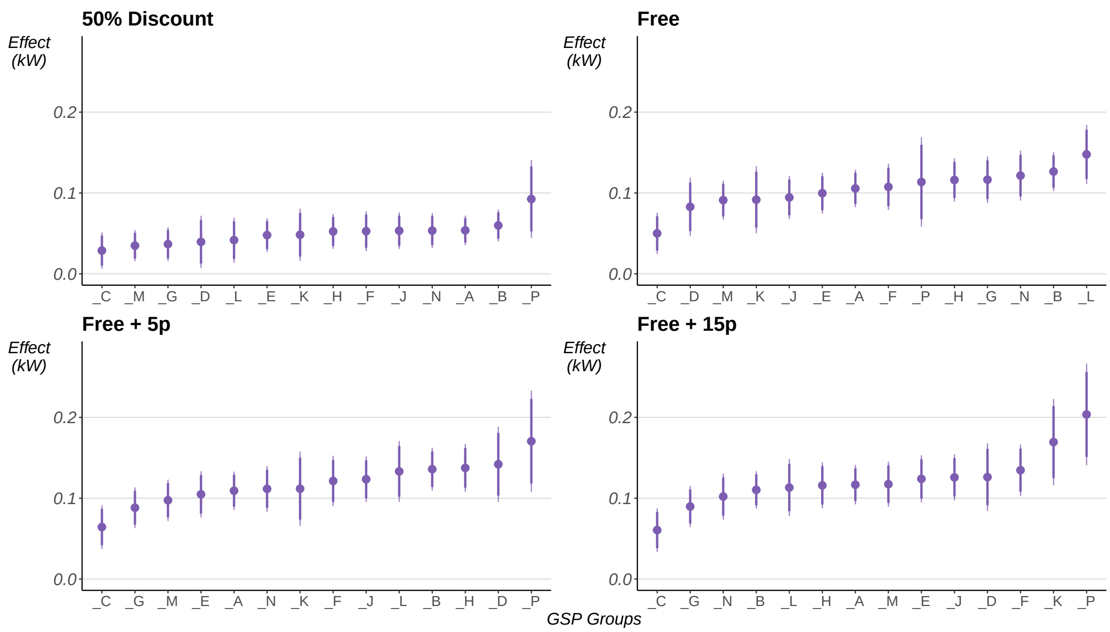
(b) Spain



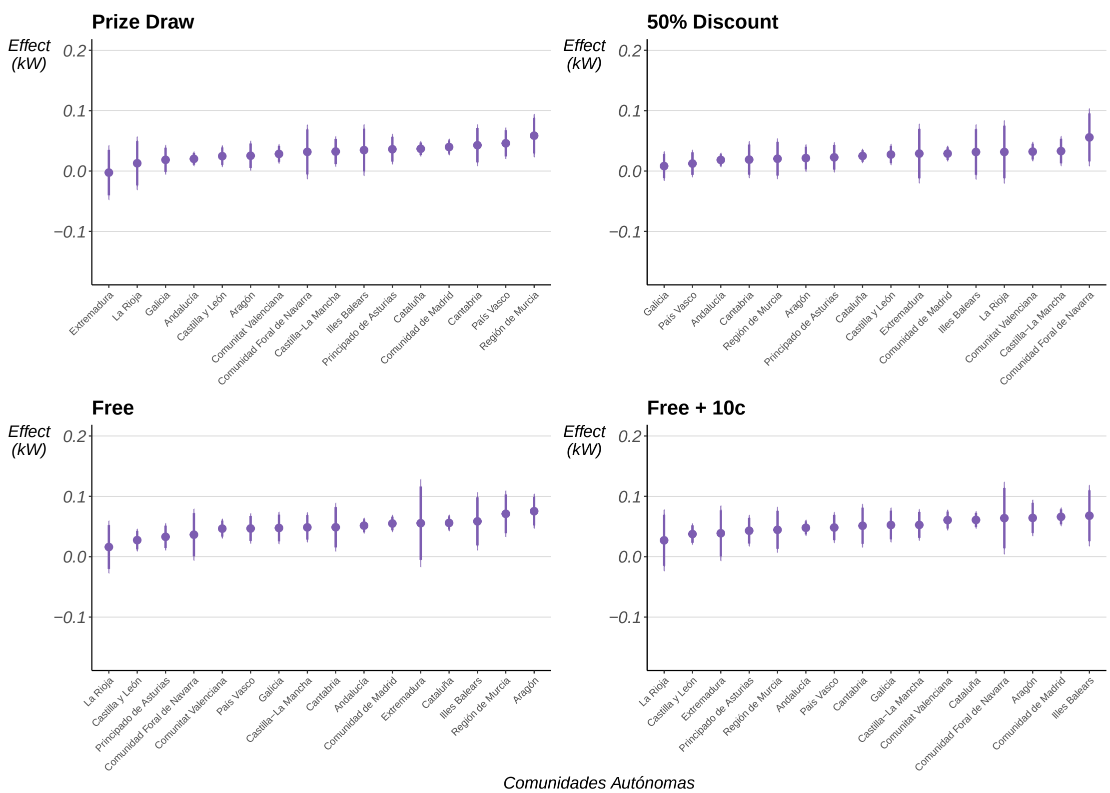
Notes: This figure shows how treatment effects vary by baseline estimated annual consumption, split into quartiles. Figure A4a shows results for Great Britain and Figure A4b shows results for Spain, with quartiles defined separately within each country. Lines depict 90% (dark) and 95% (light) confidence intervals. Standard errors are clustered at the customer level. The outcome measure is hourly electricity consumption during the event.

Figure A5: Heterogeneity by geographic region

(a) Great Britain



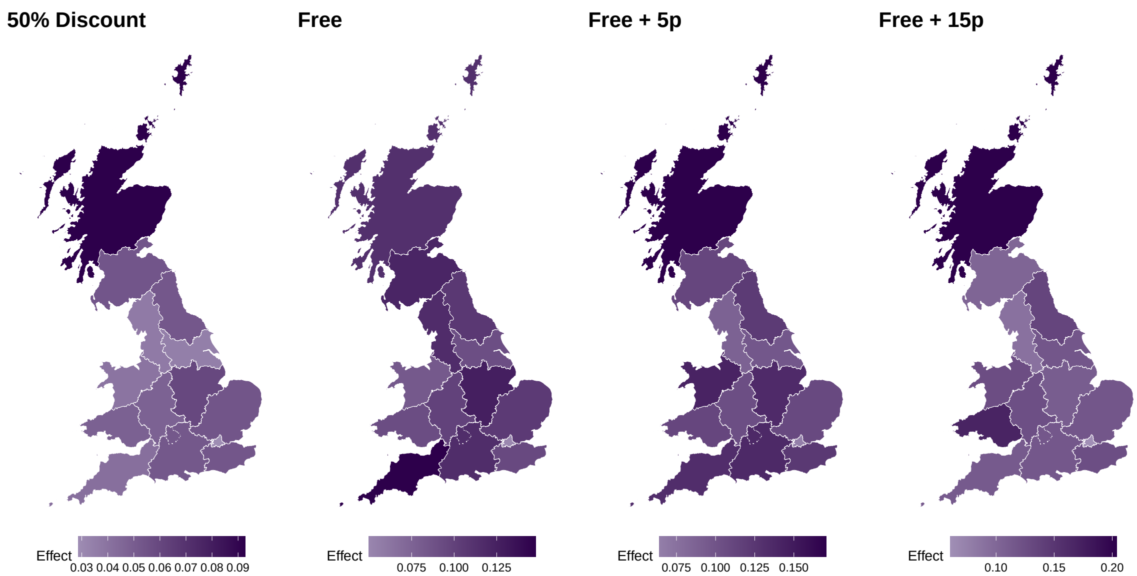
(b) Spain



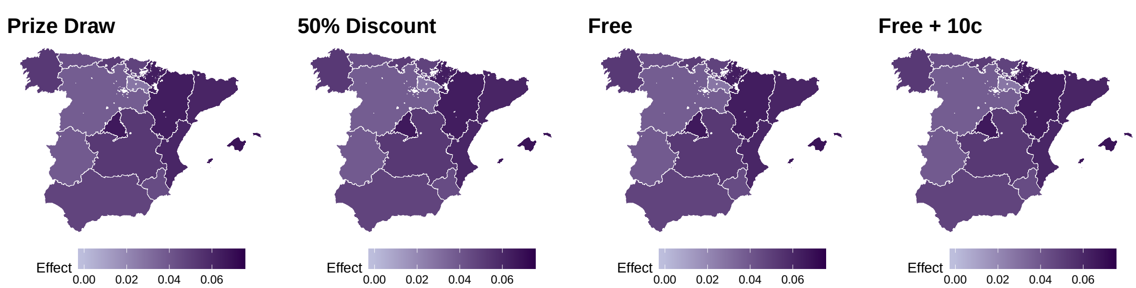
Notes: Notes: This figure shows treatment effects on hourly electricity consumption by geographic region, separately for each treatment group. Panel (a) reports estimates by Grid Supply Point (GSP) Group in Great Britain; panel (b) reports estimates by Comunidad Autónoma in Spain. Estimates are obtained by interacting treatment assignment with region indicators in the main specification. Regions are ordered by effect size within each treatment. Lines depict 90% (dark) and 95% (light) confidence intervals. Standard errors are clustered at the customer level.

Figure A6: Heterogeneity by geographic region

(a) Great Britain



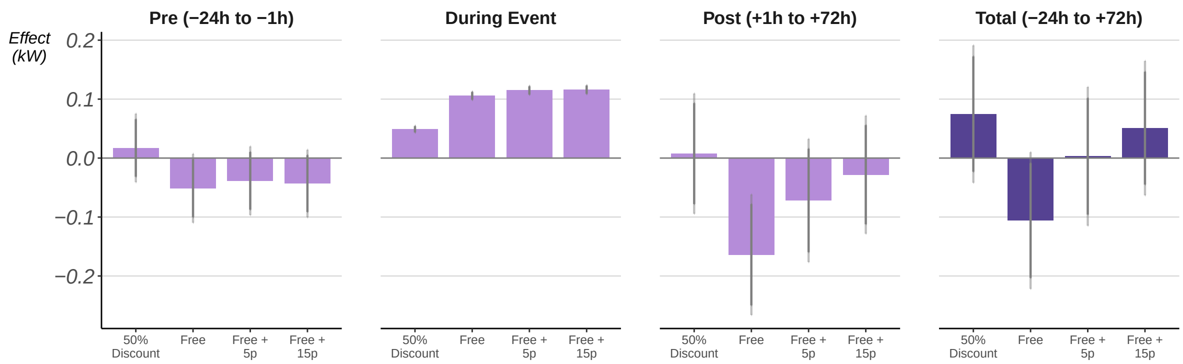
(b) Spain



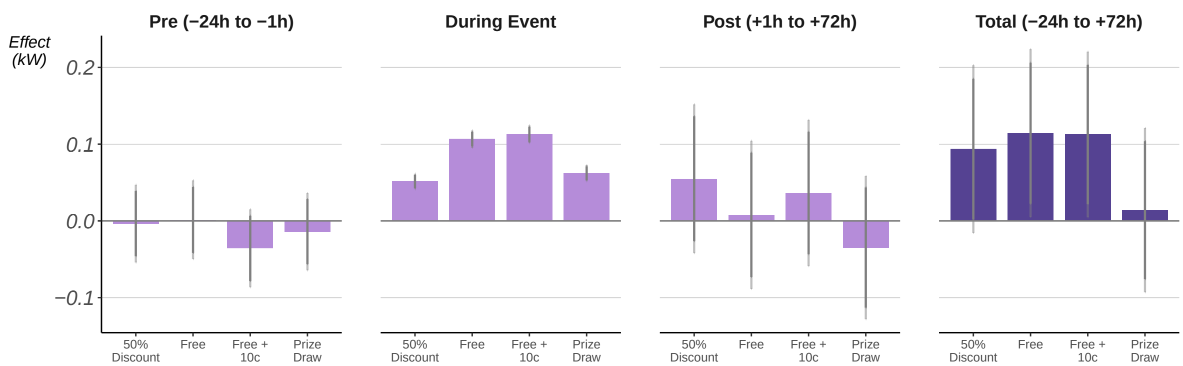
*Notes:*This figure maps estimated treatment effects on hourly electricity consumption by geographic region, separately for each treatment group. Panel (a) shows Great Britain, with regions defined by Grid Supply Point (GSP) Group. Panel (b) shows Spain, with regions defined by Comunidad Autónoma. Darker shading indicates larger treatment effects. Note that the colour scales differ across treatments within each panel to reflect the range of effects for each incentive level.

Figure A7: Robustness: Displacement analysis with unpooled treatment variables

(a) Great Britain

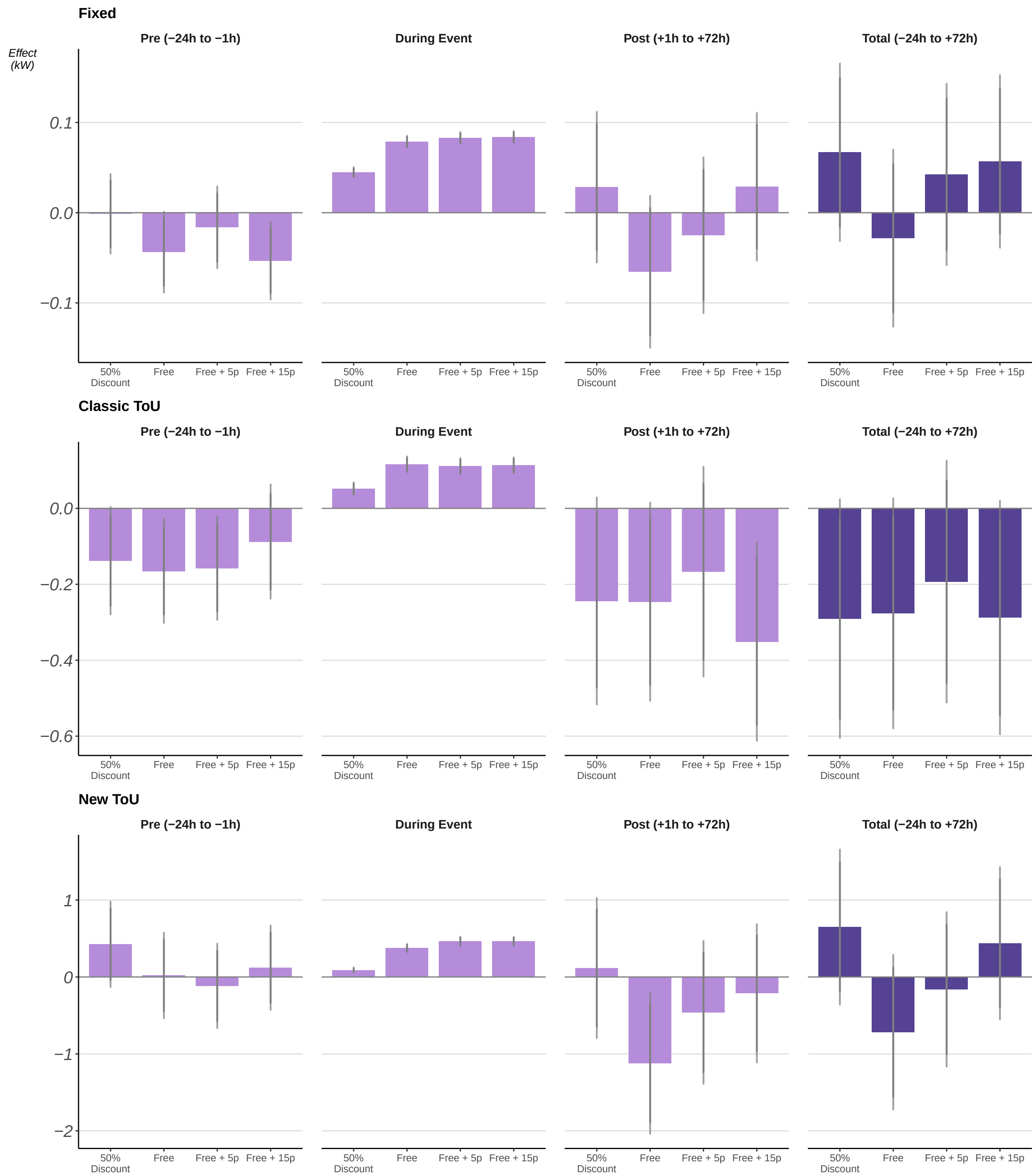


(b) Spain



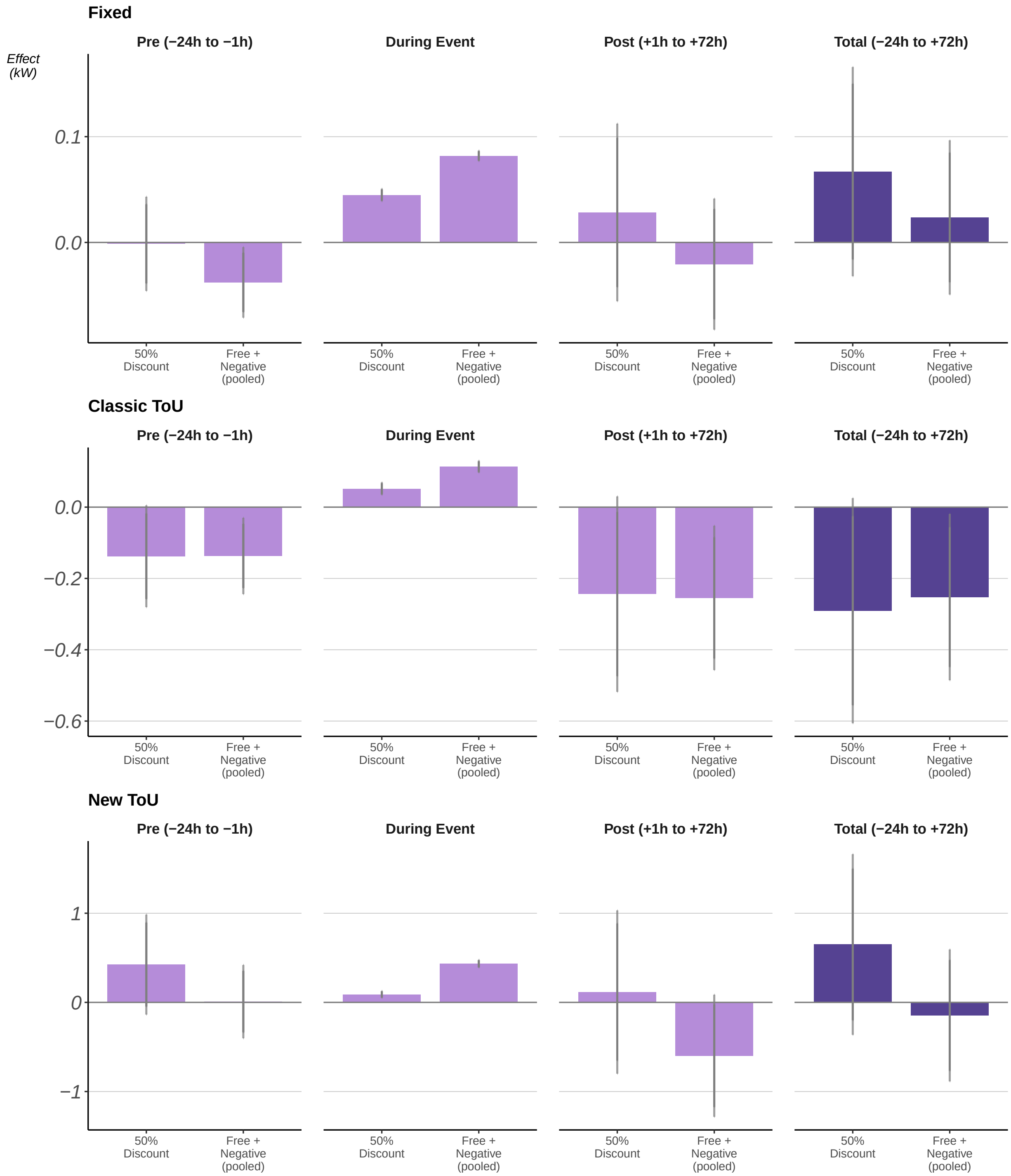
Notes: These figures plot the impact of treatment on cumulative electricity consumption in different windows. The first pane is from -24 hours to -1 hour before the event. The second pane is the hour during the event. The third pane is the total consumption during hours 1 to 72. The fourth pane is total consumption from -24 to +72 hours around the event. Shaded areas indicate 95% confidence intervals; standard errors are clustered at the customer level.

Figure A8: Heterogeneity in displacement by baseline TOU tariff - Great Britain



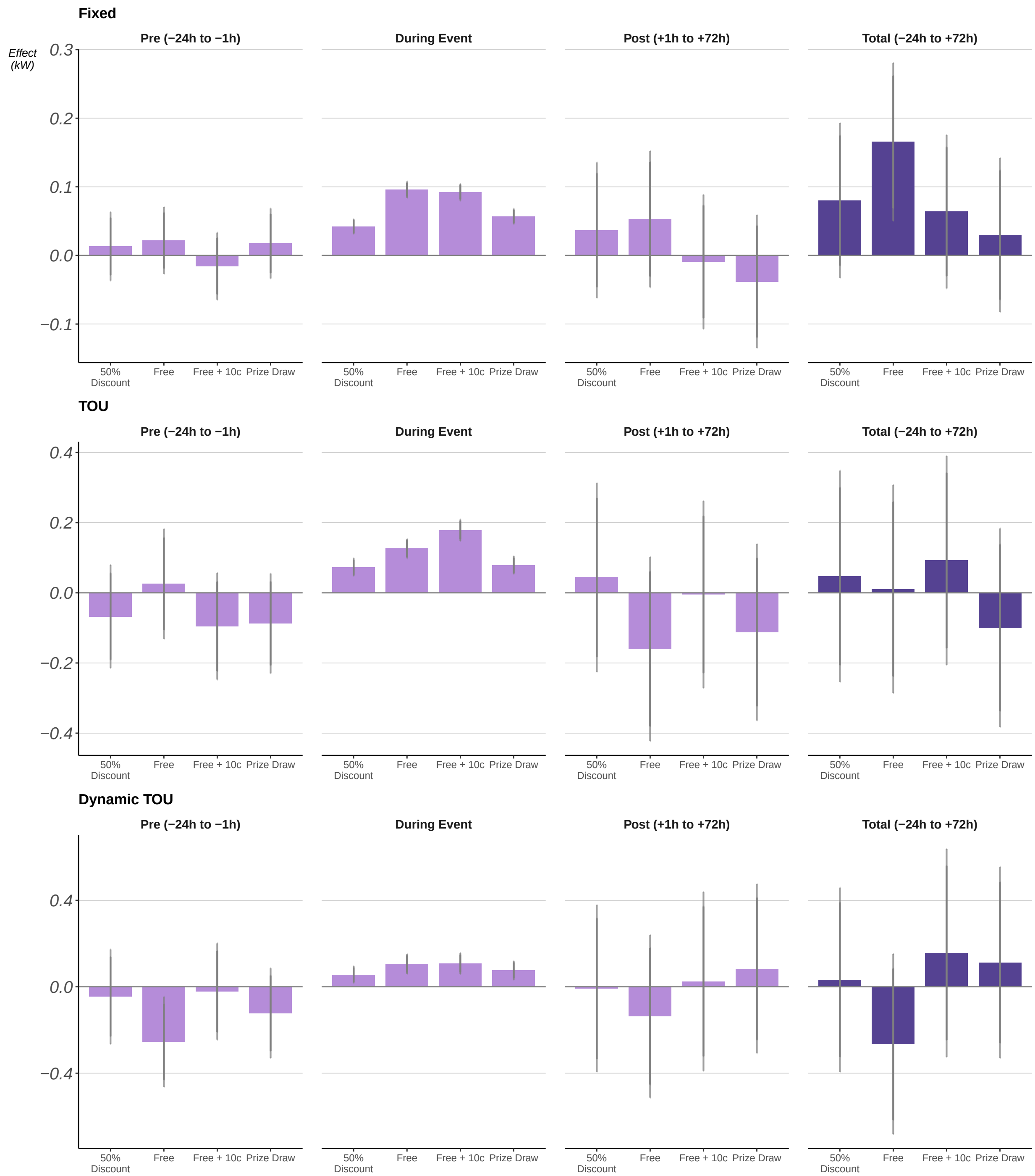
Notes: This figure shows impact of treatment on cumulative electricity consumption in different windows. Estimates come from interaction specifications that interact treatment status with tariff type and are expressed relative to the control group within each tariff. Shaded areas denote 95% confidence intervals; standard errors are clustered at the customer level.

Figure A9: Heterogeneity in displacement by baseline TOU tariff, pooled treatments - Great Britain



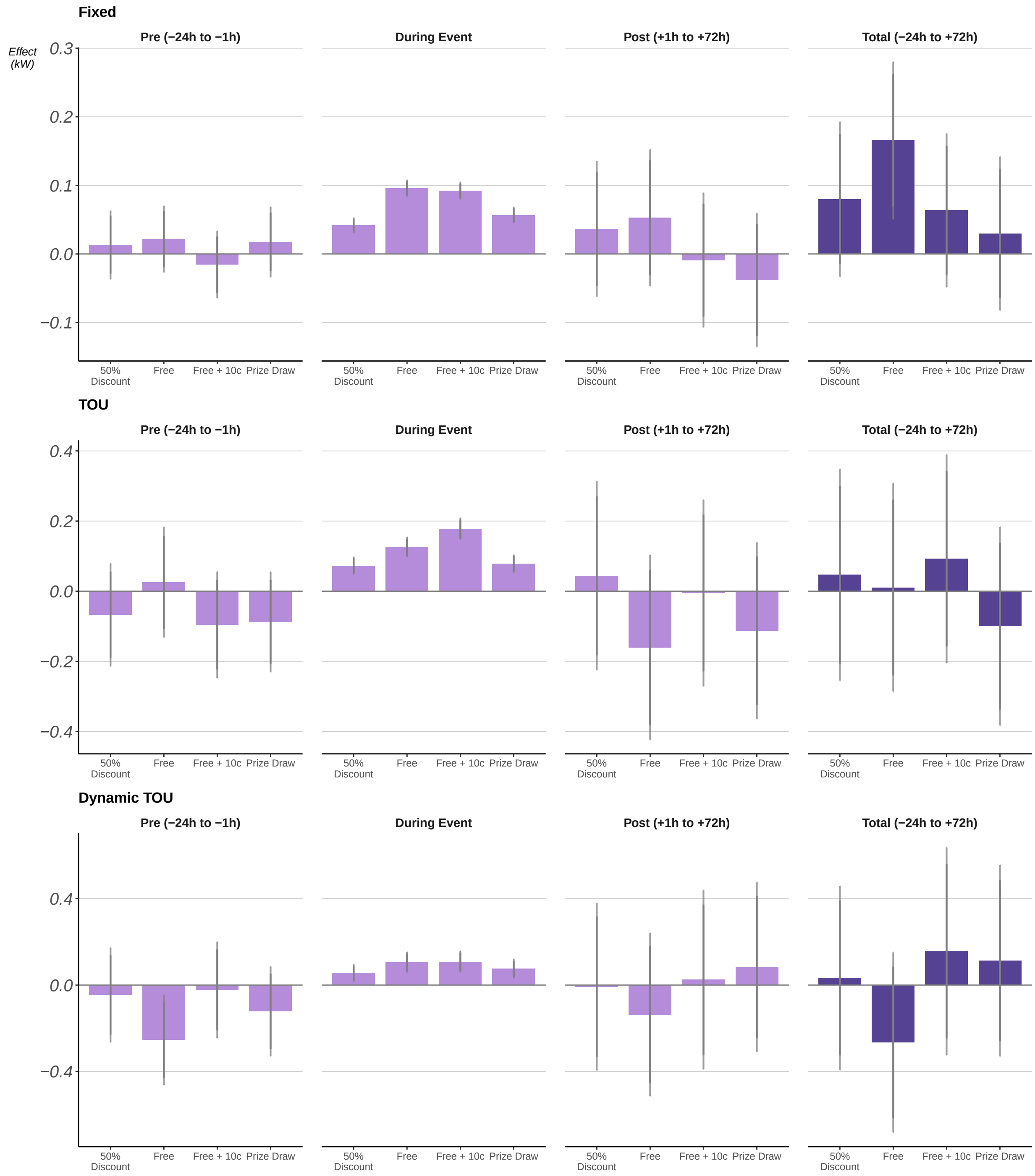
Notes: The figure shows impact of treatment on cumulative electricity consumption in different windows. Estimates come from interaction specifications that interact treatment status with tariff type and are expressed relative to the control group within each tariff. This figure pools Free, Free + 5p, and Free + 15p into one group. Shaded areas denote 95% confidence intervals; standard errors are clustered at the customer level.

Figure A10: Heterogeneity in displacement by TOU tariff - Spain



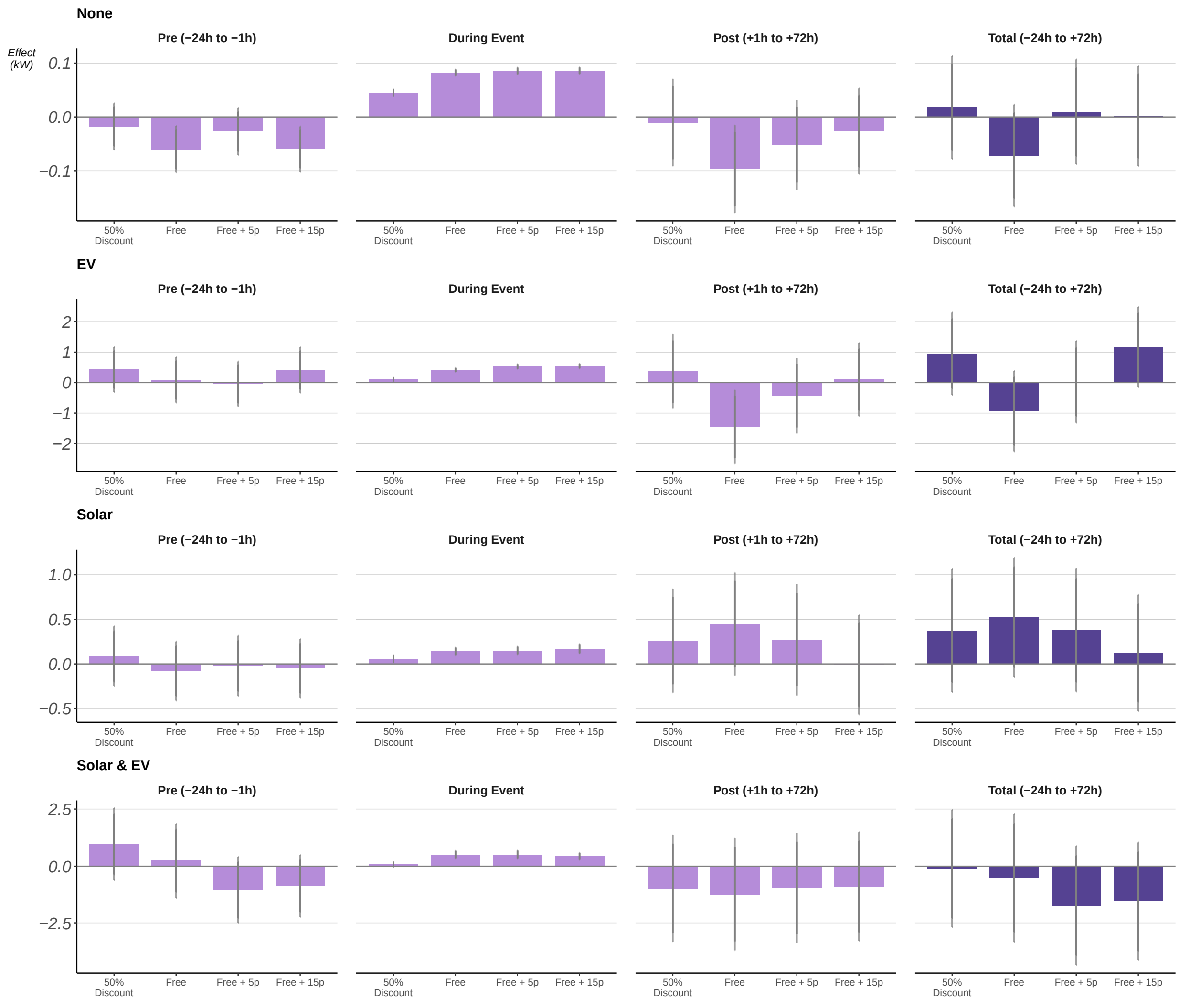
Notes: This figure shows impact of treatment on cumulative electricity consumption in different windows. Estimates come from interaction specifications that interact treatment status with tariff type and are expressed relative to the control group within each tariff. Shaded areas denote 95% confidence intervals; standard errors are clustered at the customer level.

Figure A11: Heterogeneity in Displacement by TOU tariff, pooled treatments - Spain



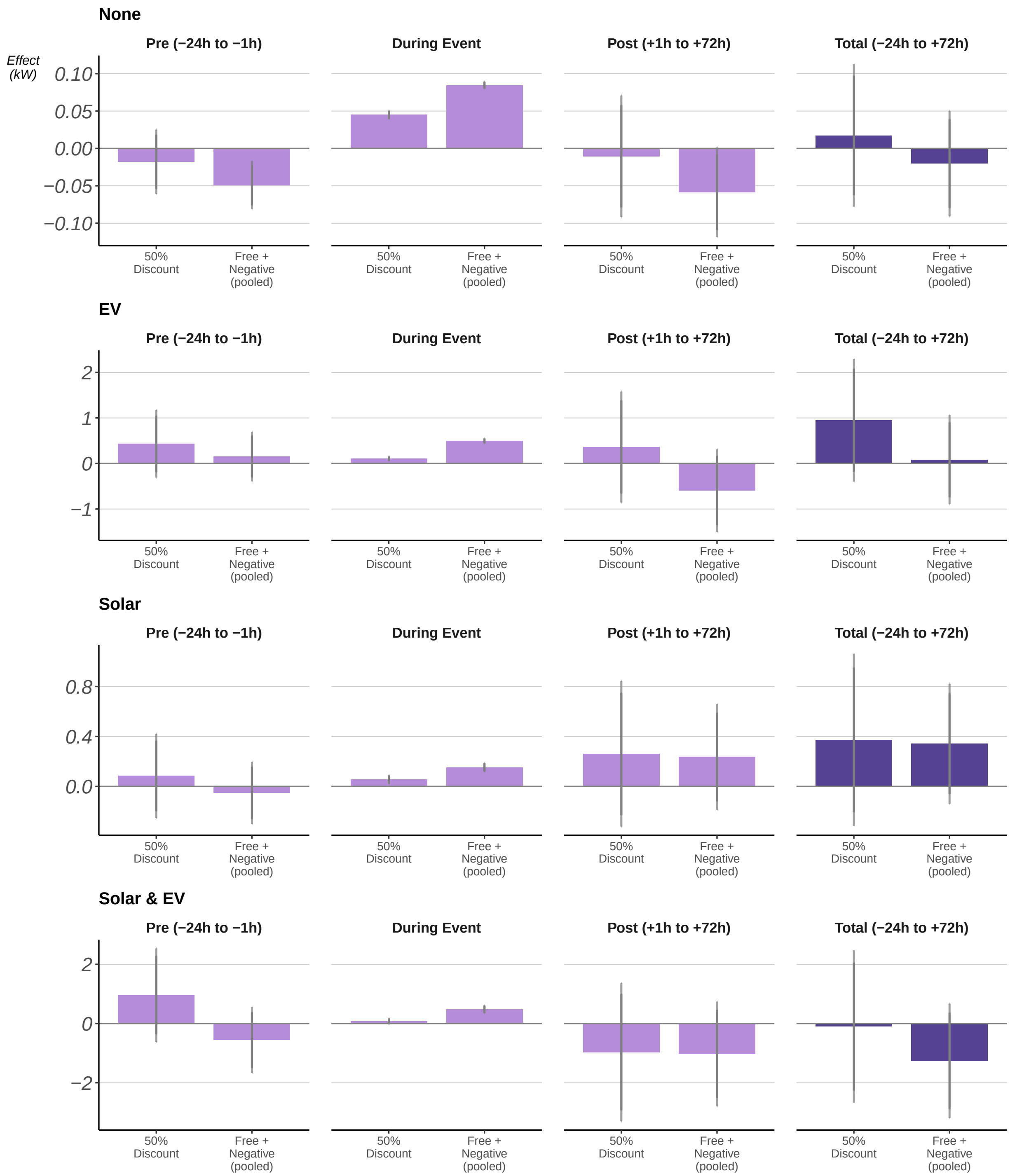
Notes: This figure shows the impact of treatment on cumulative electricity consumption in different windows. Estimates come from interaction specifications that interact treatment status with tariff type and are expressed relative to the control group within each tariff. This figure pools Free, Free + 5p, and Free + 15p into one group. Shaded areas denote 95% confidence intervals; standard errors are clustered at the customer level.

Figure A12: Heterogeneity in displacement by low-carbon technology tariff - Great Britain



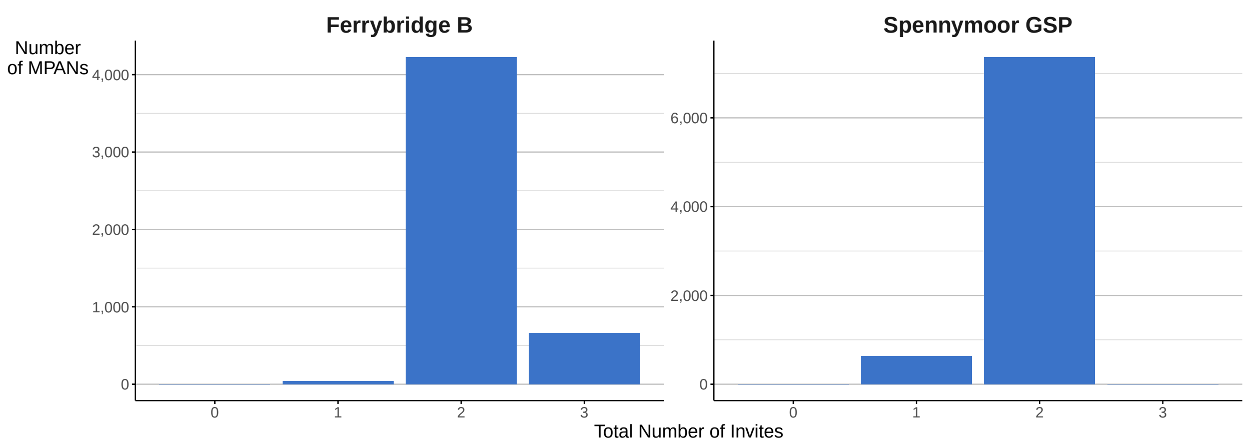
Notes: This figure shows impact of treatment on cumulative electricity consumption in different windows. Estimates come from interaction specifications that interact treatment status with LCT tariff type and are expressed relative to the control group within each LCT group. Shaded areas denote 95% confidence intervals; standard errors are clustered at the customer level.

Figure A13: Heterogeneity in displacement by low-carbon technology tariff, pooled treatments - Great Britain



Notes: This figure shows impact of treatment on cumulative electricity consumption in different windows. Estimates come from interaction specifications that interact treatment status with LCT tariff type and are expressed relative to the control group within each LCT group. This figure pools Free, Free + 5p, and Free + 15p into one group. Shaded areas denote 95% confidence intervals; standard errors are clustered at the customer level.

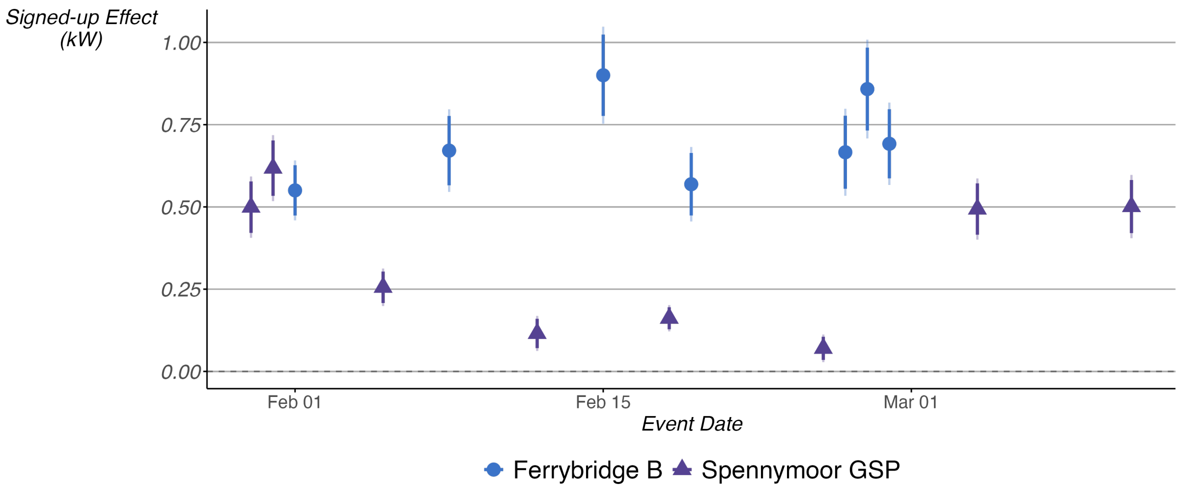
Figure A14: Number of customers invited in NPG “power-ups"



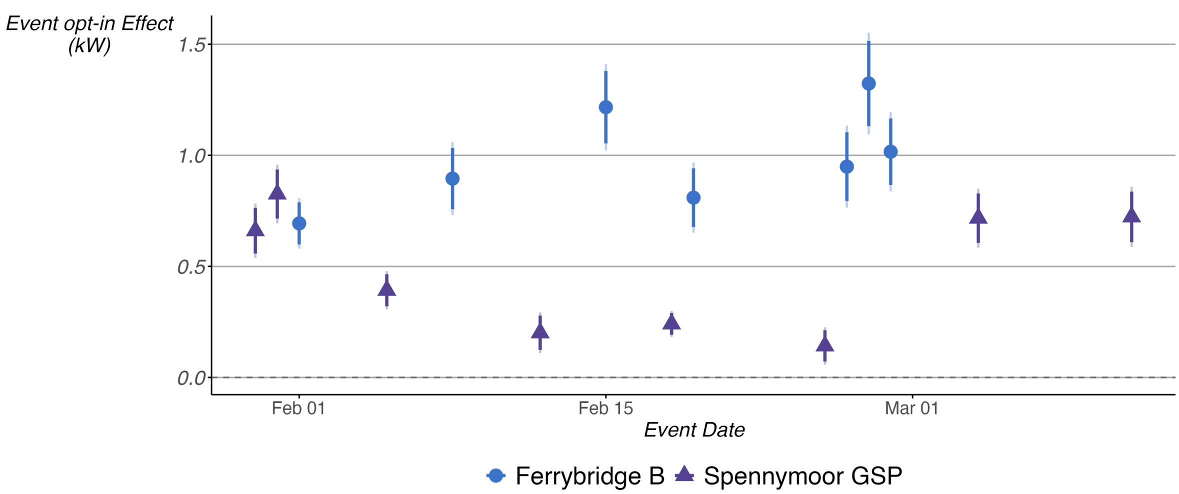
Notes: This figure plots the number of invites customers receive throughout the duration of the NPG “power-up" trials.

Figure A15: Effects of NPG “power-ups", by event day

(a) Signed up



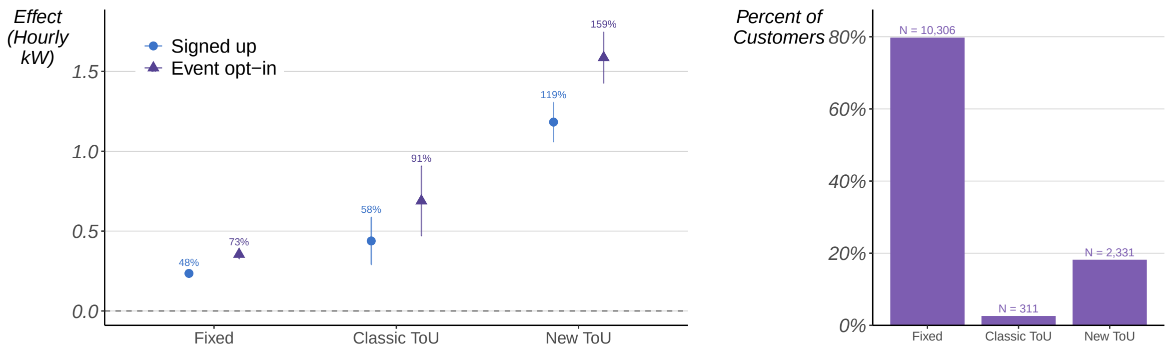
(b) Event opt-in



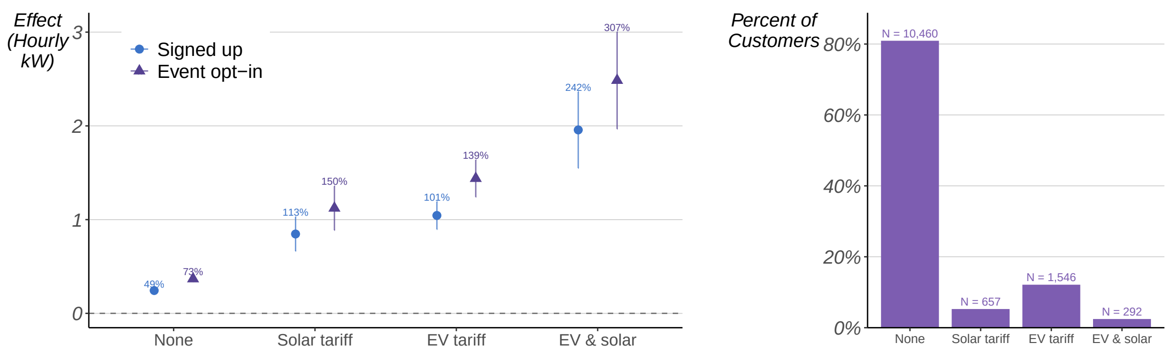
Notes: This figure reports estimates of effect of being invited (panel a) and event opt-in (panel b) separately for each event day. Each point estimate represents the effect of being invited to, or opting into, a power-up event on hourly electricity consumption on that event day. Estimates come from the main specification in Equation (2) and Equation (First Stage), estimated separately for each event day. Lines depict 95% confidence intervals. Standard errors are clustered at the customer level.

Figure A16: Heterogeneity of NPG effects bt tariff type

(a) TOU tariff type

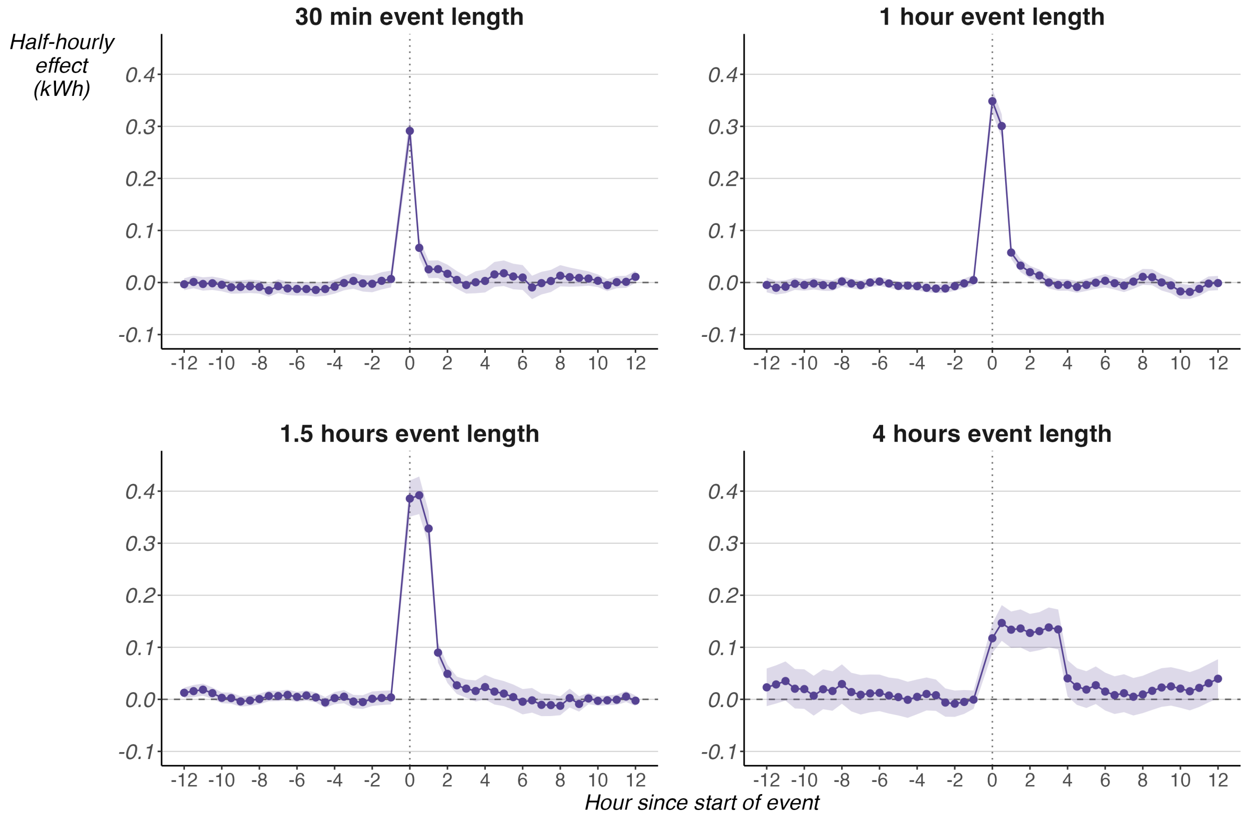


(b) LCT tariff type



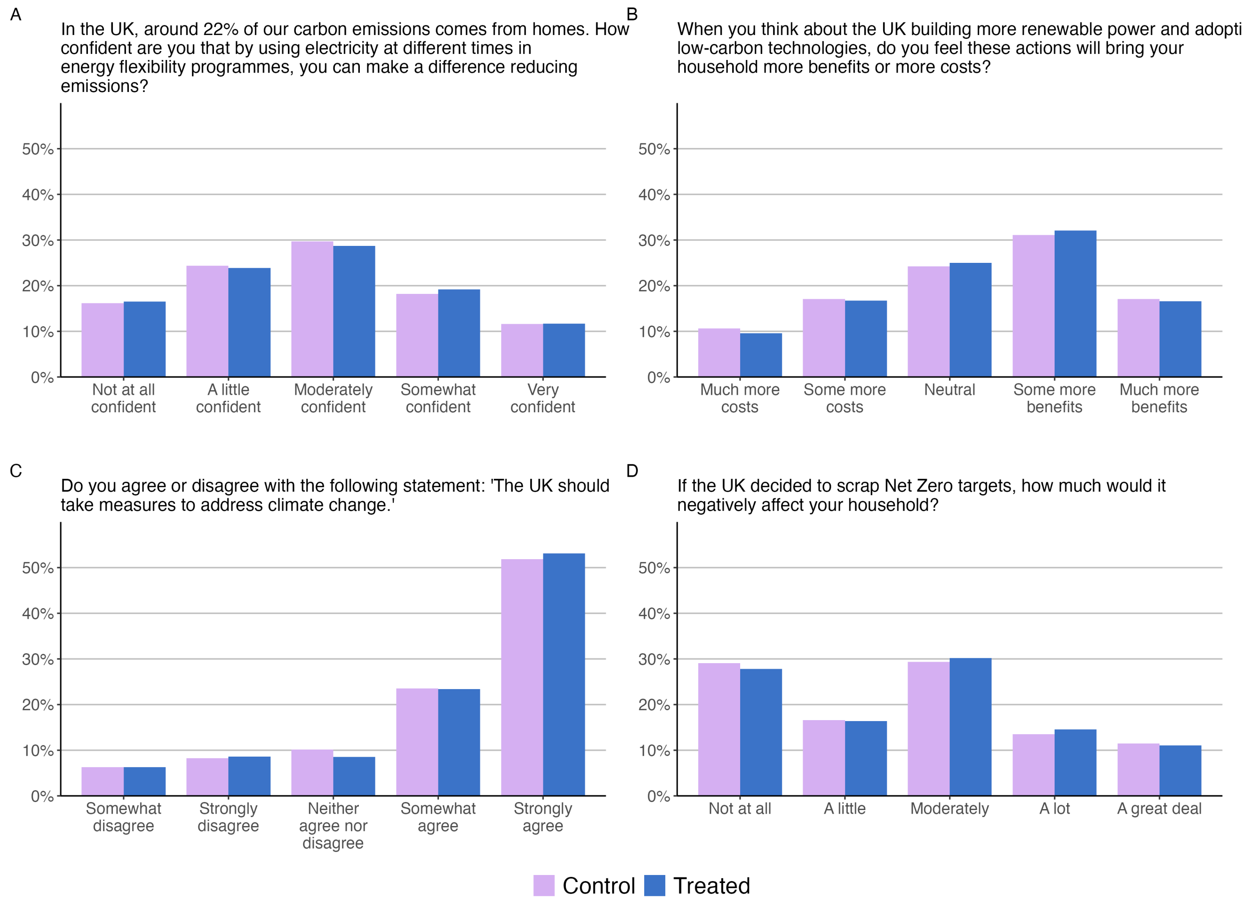
Notes: This figure reports heterogeneity in treatment effects by tariff type. Each point estimate represents the signed-up (circle) and event opt-in (triangle) treatment effects for customers on each tariff, obtained by interacting the treatment indicator with tariff type indicators in the main specification. Panel (a) shows heterogeneity by time-of-use (TOU) tariff type, distinguishing between customers on fixed tariffs, Classic TOU tariffs, and New TOU tariffs. Panel (b) shows heterogeneity by low-carbon technology (LCT) tariff type, distinguishing between customers with no LCT tariff, a solar tariff, an EV tariff, or both an EV and solar tariff. The percentage labels report the effect as a share of the control mean for that subgroup. The bar charts on the right of each panel report the share of customers in each tariff category. Lines depict 95% confidence intervals. Standard errors are clustered at the customer level.

Figure A17: NPG power-up event study analysis



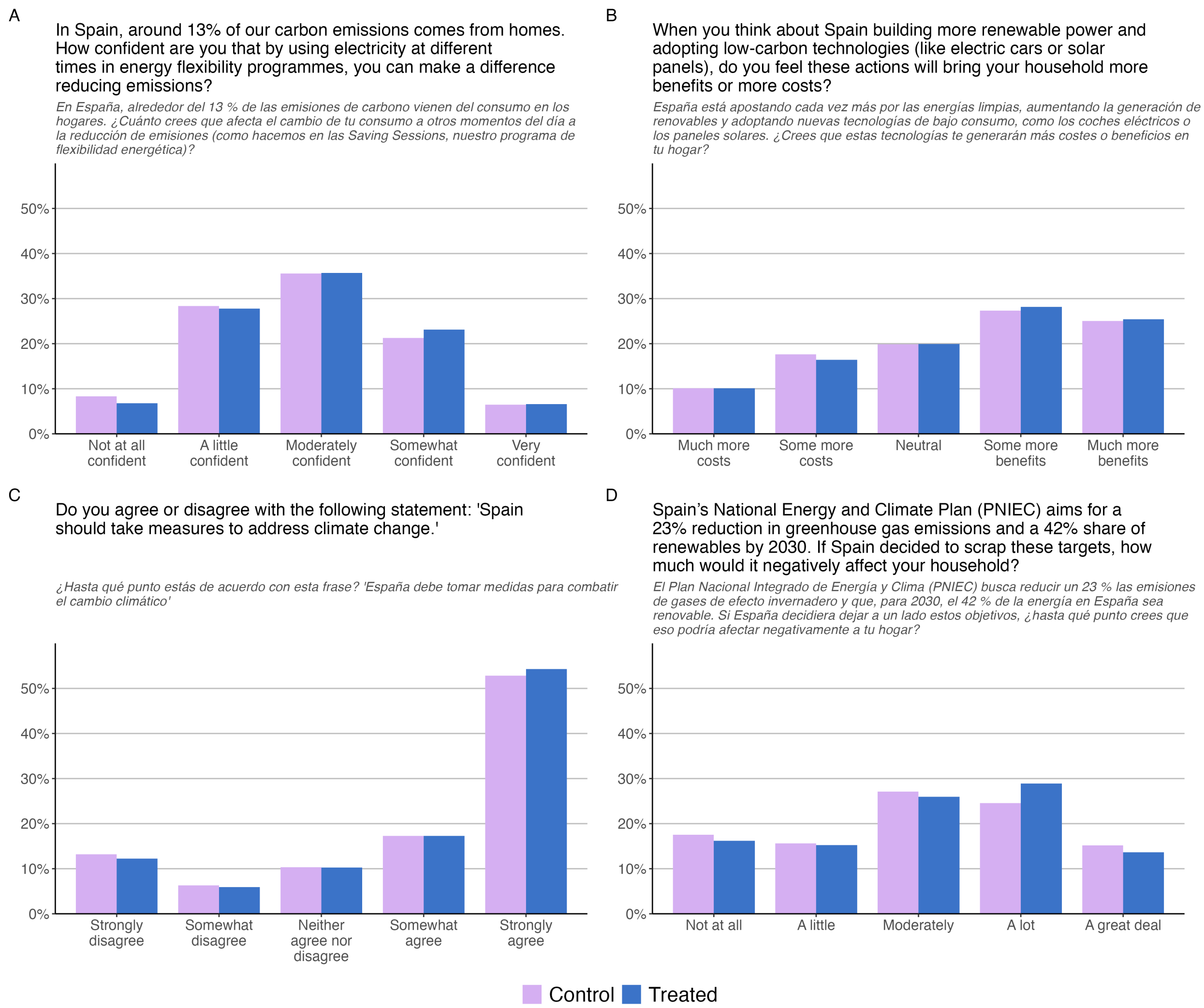
Notes: This figure reports estimates from the event-study specification, estimated separately for each event length. Each panel plots coefficients representing the half-hourly consumption response of invited customers relative to uninvited customers, at each half-hour relative to the start of the event. The omitted period is the half-hour immediately preceding the event. The sample is restricted to events where neither the 12 hours before nor the 12 hours after overlap with another event, leaving 11 event days. Of the 11 events in this sample, 2 had an event length of 30 minutes, 5 had an event length of 1 hour, 3 had an event length of 1.5 hours, and 1 had an event length of 4 hours. The vertical dashed line indicates the start of the event. Shaded areas indicate 95% confidence intervals. Standard errors are clustered at the customer level.

Figure A18: Climate sentiment survey results: Great Britain



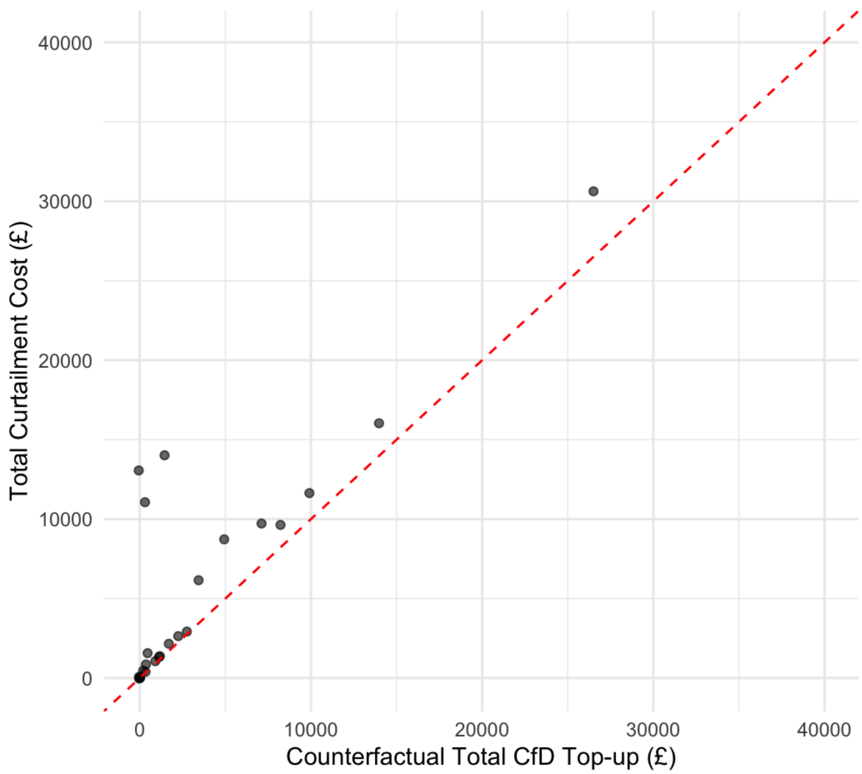
Notes: This figure shows the distribution of responses to four climate sentiment survey questions among Great Britain respondents, separately for treated customers (those who received any turn-up emails) and pure control customers. Panel A measures confidence in energy flexibility reducing emissions. Panel B captures perceived household costs versus benefits of renewable energy expansion. Panel C elicits support for government action on climate change. Panel D measures perceived household impact of abandoning Net Zero targets. Responses are measured on a five-point Likert scale. The survey was sent to 37,125 customers, with 4,621 responses received.

Figure A19: Climate sentiment survey results: Spain



Notes: This figure shows the distribution of responses to four climate sentiment survey questions among Spain respondents, separately for treated customers (those who received any turn-up emails) and pure control customers. Panel A measures confidence in energy flexibility reducing emissions. Panel B captures perceived household costs versus benefits of renewable energy and low-carbon technology adoption. Panel C elicits support for government action on climate change. Panel D measures perceived household impact of abandoning Spain's PNIEC targets. Questions are shown in both English and Spanish. Responses are measured on a five-point Likert scale. The survey was sent to 25,999 customers, with 5,533 responses received.

Figure A20: Curtailment Costs versus Counterfactual CfD Top-up Costs



Notes: Each point represents a BMU (Balancing Mechanism Unit). The x-axis shows the total counterfactual CfD top-up revenue the generator would have received absent being constrained-down, calculated as the difference between the strike price and the IMRP multiplied by curtailed MWh. The y-axis shows the total observed curtailment cost paid through the Balancing Mechanism for the constraint-down service. The 45-degree dashed line indicates parity between counterfactual CfD payments and observed curtailment costs. Values are aggregated over all settlement periods in the sample (19 February 2025 through 18 February 2026).

A.3 Implementation Details

A.3.1 Eligibility

In Great Britain, our implementing partner had the following required exclusions:

- Have enrolled or been contaced about other turn-up campaigns, which include: NPG power-ups, LCM power-ups, and UKPN power-ups
- Are enrolled in the Free Electricity Octoplus campaign, which are similar to the events in this experiment in that they give Octopus customers Free Electricity at certain times.
- Customers on Agile Octopus tariffs, which is a real-time tariff that tracks wholesale electricity prices on a half-hourly basis. These customers already respond to negative wholesale prices.

In Spain, our implementing partner had the following required exclusions:

- Self-employed customers
- Customers with an ATR code ("Acceso de Terceros a la Red") different from 2.0TD. This excluded higher voltage connections
- Customers who opted out of marketing communications
- Vulnerable customers
- Customers with open complaints
- Customers who have not received a bill in more than 60 days
- Customers whose agreement with Octopus Energy is scheduled to be renewed between 30 and 60 days after the first session begins
- Customers whose primary address is in the Canary Islands
- Customers in distribution zones unable to send smart meter data within 5 days

We additionally excluded customers participating in existing Octopus programs (Solar Family, Sun Club, and "Comunidad Octoamigos") and those enrolled in electric vehicle tariffs, since our partner planned to run concurrent flexibility campaigns with these groups. Customers exporting solar generation were also excluded due to billing complexity.

In our pre-analysis plan, we stated that these exclusions yielded a sample of 66,441 customers. After the first event, however, we identified an implementation error: 2,486 customers who were participating in other flexibility programs or enrolled in an electric vehicle tariff had been inadvertently included. After the second event, our implementing partner also determined that customers holding multiple accounts should be excluded. Some of these accounts were eligible while others were not, which created customer confusion and imposed additional operational burdens. We therefore excluded 2,853 such customers. Finally, 664 customers either left Octopus Energy Spain or became ineligible between sampling and the first event.

A.3.2 Matched pair randomization

In Great Britain, to assign customers to treatment conditions across the five events, we constructed two Latin squares, generating 20 unique treatment sequences. Each sequence specifies a distinct ordering in which a customer is exposed to each of the five conditions (four treatments and one rotating control). We additionally defined four sequences in which customers were never treated in any of the five events, forming a pure control group. In total, this yielded 24 distinct assignment sequences.

Within our sample, we then implemented a matched-pair randomization to assign sampled households to experimental conditions across five events, with the aim of ensuring pairwise treatment balance over time. We did this through the following steps:

1. Strata for Randomization: We created randomization strata based on dimensions: (1) property value tercile, interacted with urban/rural classification, (2) property type (house vs. non-house), and (3) baseline tariff type
2. Blocking: Within each stratum, we ranked accounts by electricity consumption and grouped them into blocks of 24.
3. Sequence Assignment: For each block, we randomly assigned one of 24 pre-generated balanced Latin square sequences of treatments (5 treatments across 5 events) and

pure control sequences. These sequences ensure that each treatment precedes and follows every other treatment equally often across blocks.

4. Misfits: Accounts that did not fit into full blocks were pooled and randomly assigned to treatment sequences from the same set of 24 sequences.

In Spain, we followed a similar randomization strategy. We again used two Latin squares to generate 20 treatment sequences and included an additional six sequences in which customers were never treated, yielding 26 total sequences. In the absence of covariates for stratified randomization, we relied on a straightforward matched-pair randomization:

1. Blocking: We ranked customer accounts by average electricity consumption between 1pm and 4pm in May 2025—a period during which turn-up events are most likely to occur—and grouped them into blocks of 26.

2. Sequence Assignment: For each block, we randomly assigned one of 26 pre-generated balanced Latin square sequences of treatments (5 treatments across 5 events) and pure control sequences. These sequences ensure that each treatment precedes and follows every other treatment equally often across blocks.

3. Misfits: Accounts that did not fit into full blocks were randomly assigned to treatment sequences from the same set of 26 sequences.

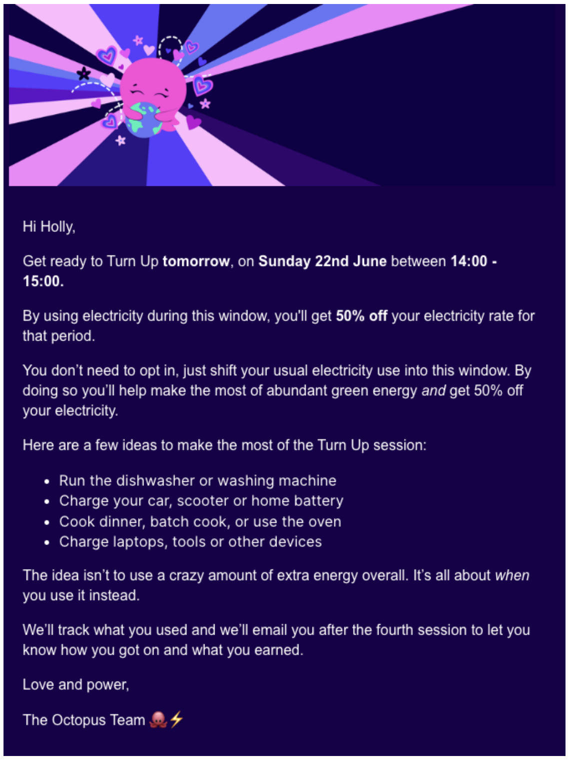
A.3.3 Email Delivery

A.4 Impact of turn-up participation on climate policy sentiment

One possible implication of turn-up events is that exposure to periods of abundant renewable generation (and potential financial gains) may help customers better connect renewable energy availability to personal financial benefits. This, in turn, could shape broader beliefs about the feasibility and desirability of climate and renewable energy policies. To examine this possibility, we conducted a post-experiment survey following the completion of the five events.

The survey consisted of four questions with responses measured on a five-point Likert scale, designed to capture customers' climate-related sentiments. The questions were broadly comparable across the two countries, with the Spanish version translated and

Figure A21: Great Britain Treatment emails



Hi Holly,

Get ready to Turn Up **tomorrow**, on **Sunday 22nd June** between **14:00 - 15:00.**

By using electricity during this window, you'll get **50% off** your electricity rate for that period.

You don't need to opt in, just shift your usual electricity use into this window. By doing so you'll help make the most of abundant green energy *and* get 50% off your electricity.

Here are a few ideas to make the most of the Turn Up session:

- Run the dishwasher or washing machine
- Charge your car, scooter or home battery
- Cook dinner, batch cook, or use the oven
- Charge laptops, tools or other devices

The idea isn't to use a crazy amount of extra energy overall. It's all about *when* you use it instead.

We'll track what you used and we'll email you after the fourth session to let you know how you got on and what you earned.

Love and power,

The Octopus Team 🐙⚡

(a) Subject: Get ready to turn-up: 50% off your electricity tomorrow from 14:00 - 15:00

Hi Sandra,

Get ready to Turn Up **tomorrow**, on **Sunday 22st June** between **14:00 - 15:00.**

Any electricity you use during this time will be **totally free.**

That's right! You won't need to pay for your electricity during this time, instead *it will be free*.

You don't need to opt in, just shift your usual electricity use into this window. By doing so you'll help make the most of abundant green energy *and* get free electricity.

Here are a few ideas to make the most of the Turn Up session:

- Run the dishwasher or washing machine
- Charge your car, scooter or home battery
- Cook dinner, batch cook, or use the oven
- Charge laptops, tools or other devices

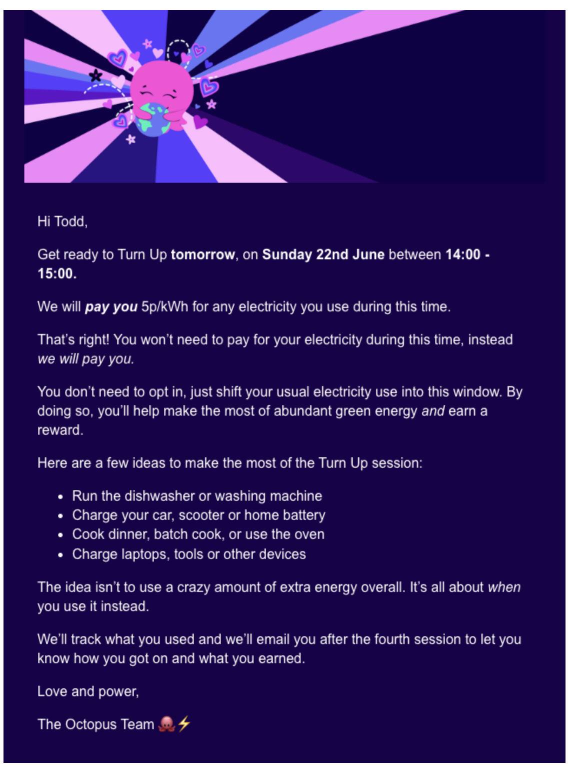
The idea isn't to use a crazy amount of extra energy overall. It's all about *when* you use it instead.

We'll track what you used and we'll email you after the fourth session to let you know how you got on and what you earned.

Love and power,

The Octopus Team 🐙⚡

(b) Subject: Get ready to turn-up: free electricity tomorrow from 14:00 - 15:00



Hi Todd,

Get ready to Turn Up **tomorrow**, on **Sunday 22nd June** between **14:00 - 15:00.**

We will ***pay you*** 5p/kWh for any electricity you use during this time.

That's right! You won't need to pay for your electricity during this time, instead *we will pay you.*

You don't need to opt in, just shift your usual electricity use into this window. By doing so, you'll help make the most of abundant green energy *and* earn a reward.

Here are a few ideas to make the most of the Turn Up session:

- Run the dishwasher or washing machine
- Charge your car, scooter or home battery
- Cook dinner, batch cook, or use the oven
- Charge laptops, tools or other devices

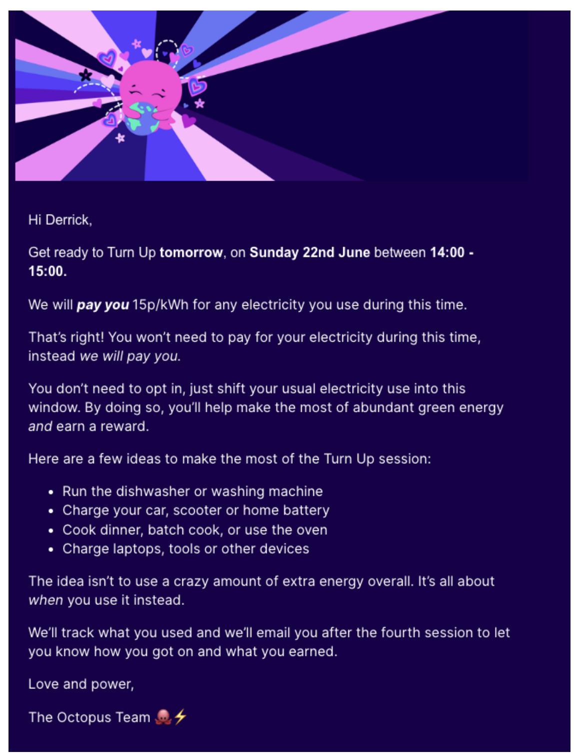
The idea isn't to use a crazy amount of extra energy overall. It's all about *when* you use it instead.

We'll track what you used and we'll email you after the fourth session to let you know how you got on and what you earned.

Love and power,

The Octopus Team 🐙⚡

(c) Get ready to turn-up: free electricity + earn 5p/kWh tomorrow from 14:00 - 15:00



Hi Derrick,

Get ready to Turn Up **tomorrow**, on **Sunday 22nd June** between **14:00 - 15:00.**

We will ***pay you*** 15p/kWh for any electricity you use during this time.

That's right! You won't need to pay for your electricity during this time, instead *we will pay you.*

You don't need to opt in, just shift your usual electricity use into this window. By doing so, you'll help make the most of abundant green energy *and* earn a reward.

Here are a few ideas to make the most of the Turn Up session:

- Run the dishwasher or washing machine
- Charge your car, scooter or home battery
- Cook dinner, batch cook, or use the oven
- Charge laptops, tools or other devices

The idea isn't to use a crazy amount of extra energy overall. It's all about *when* you use it instead.

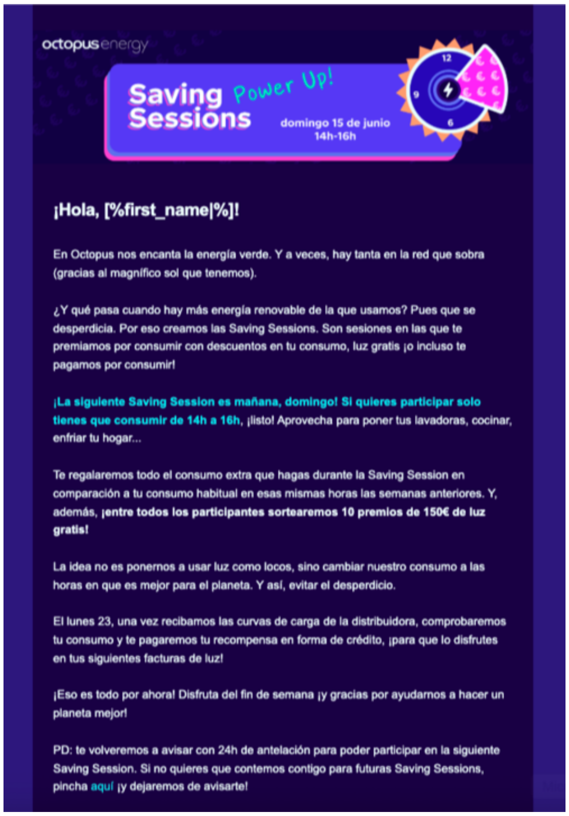
We'll track what you used and we'll email you after the fourth session to let you know how you got on and what you earned.

Love and power,

The Octopus Team 🐙⚡

(d) Get ready to turn-up: free electricity + earn 15p/kWh tomorrow from 14:00 - 15:00

Figure A22: Spain Treatment emails



octopusenergy

Saving Sessions Power Up!

domingo 15 de junio 14h-16h

¡Hola, [%first_name|%]!

En Octopus nos encanta la energía verde. Y a veces, hay tanta en la red que sobra (gracias al magnífico sol que tenemos).

¿Y qué pasa cuando hay más energía renovable de la que usamos? Pues que se desperdicia. Por eso creamos las Saving Sessions. Son sesiones en las que te premiamos por consumir con descuentos en tu consumo, luz gratis ¡o incluso te pagamos por consumir!

¡La siguiente Saving Session es mañana, domingo! Si quieres participar solo tienes que consumir de 14h a 16h, ¡listo! Aprovecha para poner tus lavadoras, cocinar, enfriar tu hogar...

Te regalaremos todo el consumo extra que hagas durante la Saving Session en comparación a tu consumo habitual en esas mismas horas las semanas anteriores. Y, además, **¡entre todos los participantes sortearemos 10 premios de 150€ de luz gratis!**

La idea no es ponernos a usar luz como locos, sino cambiar nuestro consumo a las horas en que es mejor para el planeta. Y así, evitar el desperdicio.

El lunes 23, una vez recibamos las curvas de carga de la distribuidora, comprobaremos tu consumo y te pagaremos tu recompensa en forma de crédito, ¡para que lo disfrutes en tus siguientes facturas de luz!

¡Eso es todo por ahora! Disfruta del fin de semana ¡y gracias por ayudarnos a hacer un planeta mejor!

PD: te volveremos a avisar con 24h de antelación para poder participar en la siguiente Saving Session. Si no quieres que contemos contigo para futuras Saving Sessions, pincha aquí ¡y dejaremos de avisarte!

(a) Prize Draw

octopusenergy

Saving Sessions Power Up!

domingo 15 de junio 14h-16h

¡Hola, [%first_name|%]!

En Octopus nos encanta la energía verde. Y a veces, hay tanta en la red que sobra (gracias al magnífico sol que tenemos).

¿Y qué pasa cuando hay más energía renovable de la que usamos? Pues que se desperdicia. Por eso creamos las Saving Sessions. Son sesiones en las que te premiamos por consumir con descuentos en tu consumo, luz gratis ¡o incluso te pagamos por consumir!

¡La siguiente Saving Session es mañana, domingo! Si quieres participar solo tienes que consumir de 14h a 16h, ¡listo! Aprovecha para poner tus lavadoras, cocinar, enfriar tu hogar...

Toda la luz que uses durante esas dos horas la tendrás al 50% de descuento.

La idea no es ponernos a usar luz como locos, sino cambiar nuestro consumo a las horas en que es mejor para el planeta. Y así, evitar el desperdicio.

El lunes 23, una vez recibamos las curvas de carga de la distribuidora, comprobaremos tu consumo y te pagaremos tu recompensa en forma de crédito, ¡para que lo disfrutes en tus siguientes facturas de luz!

¡Eso es todo por ahora! Disfruta del fin de semana ¡y gracias por ayudarnos a hacer un planeta mejor!

PD: te volveremos a avisar con 24h de antelación para poder participar en la siguiente Saving Session. Si no quieres que contemos contigo para futuras Saving Sessions, pincha aquí ¡y dejaremos de avisarte!

(b) 50% Discount

octopusenergy

Saving Sessions Power Up!

domingo 15 de junio 14h-16h

¡Hola, [%first_name|%]!

En Octopus nos encanta la energía verde. Y a veces, hay tanta en la red que sobra (gracias al magnífico sol que tenemos).

¿Y qué pasa cuando hay más energía renovable de la que usamos? Pues que se desperdicia. Por eso creamos las Saving Sessions. Son sesiones en las que te premiamos por consumir con descuentos en tu consumo, luz gratis ¡o incluso te pagamos por consumir!

¡La siguiente Saving Session es mañana, domingo! Si quieres participar solo tienes que consumir de 14h a 16h, ¡listo! Aprovecha para poner tus lavadoras, cocinar, enfriar tu hogar...

¡Toda la luz que uses durante esas dos horas te saldrá totalmente gratis!

La idea no es ponernos a usar luz como locos, sino cambiar nuestro consumo a las horas en que es mejor para el planeta. Y así, evitar el desperdicio.

El lunes 23, una vez recibamos las curvas de carga de la distribuidora, comprobaremos tu consumo y te pagaremos tu recompensa en forma de crédito, ¡para que lo disfrutes en tus siguientes facturas de luz!

¡Eso es todo por ahora! Disfruta del fin de semana ¡y gracias por ayudarnos a hacer un planeta mejor!

PD: te volveremos a avisar con 24h de antelación para poder participar en la siguiente Saving Session. Si no quieres que contemos contigo para futuras Saving Sessions, pincha aquí ¡y dejaremos de avisarte!

(c) Free electricity

octopusenergy

Saving Sessions Power Up!

domingo 15 de junio 14h-16h

¡Hola, [%first_name|%]!

En Octopus nos encanta la energía verde. Y a veces, hay tanta en la red que sobra (gracias al magnífico sol que tenemos).

¿Y qué pasa cuando hay más energía renovable de la que usamos? Pues que se desperdicia. Por eso creamos las Saving Sessions. Son sesiones en las que te premiamos por consumir con descuentos en tu consumo, luz gratis ¡o incluso te pagamos por consumir!

¡La siguiente Saving Session es mañana, domingo! Si quieres participar solo tienes que consumir de 14h a 16h, ¡listo! Aprovecha para poner tus lavadoras, cocinar, enfriar tu hogar...

Te regalaremos toooda la luz que uses durante esas dos horas y, además, ¡te pagaremos 0,10€/kWh por la energía que consumas! (Sí, sí... has leído bien, ¡te pagamos por consumir!)

La idea no es ponernos a usar luz como locos, sino cambiar nuestro consumo a las horas en que es mejor para el planeta. Y así, evitar el desperdicio.

El lunes 23, una vez recibamos las curvas de carga de la distribuidora, comprobaremos tu consumo y te pagaremos tu recompensa en forma de crédito, ¡para que lo disfrutes en tus siguientes facturas de luz!

¡Eso es todo por ahora! Disfruta del fin de semana ¡y gracias por ayudarnos a hacer un planeta mejor!

PD: te volveremos a avisar con 24h de antelación para poder participar en la siguiente Saving Session. Si no quieres que contemos contigo para futuras Saving Sessions, pincha aquí ¡y dejaremos de avisarte!

(d) Free + 10c/kWh

slightly adapted for the local context. The first question measures customer sentiment toward energy flexibility. The second captures perceived household costs versus benefits of renewable energy expansion and low-carbon technologies. The third elicits overall support for government action on climate change, and the fourth measures perceived household impacts of abandoning Net Zero targets. The exact questions and translations are shown in Figure A18 and Figure A19. We sent the survey to 37,125 customers in Great Britain and 25,999 customers in Spain. We received 4,621 responses in Great Britain and 5,533 responses in Spain.

To test if participation in turn-up had any effect, we ran the following regression:

$$Y_i = \alpha + \beta Treated_i + OctopusSentiment_i + \mu_i + \varepsilon_i \tag{8}$$

Where Y_i denotes the response to a given survey question, coded from 1 (most negative toward climate policy and renewables) to 5 (most positive). $Treated_i$ is an indicator equal to one if customer i received any turn-up emails, and zero if the customer was assigned to the pure control group. $OctopusSentiment_i$ captures responses to the survey question, "We're driving the green energy revolution—building more renewable generation, electrifying homes with heat pumps and other clean technologies, and switching to EVs. How well does our mission align with your own priorities?" This variable is included as a control to account for potential response bias or changes in sentiment toward Octopus Energy induced by participation in the turn-up events, which could otherwise be conflated with broader climate sentiment. Finally, μ_i denotes matched-pair block fixed effects from the original randomization.

Across all survey questions, we find no differences between responses from treated customers and those in the pure control group in either country, indicating that participation in turn-up events did not affect overall climate sentiment (Table A10, Table A11). Notably, the raw response distributions for the four climate-sentiment questions are strikingly similar across Great Britain and Spain (Figure A18, Figure A19), suggesting broadly comparable baseline attitudes toward climate policy in the two contexts.