

# UC San Diego

## UC San Diego Previously Published Works

### Title

Unintended Effects of Residential Energy Storage on Emissions from the Electric Power System

### Permalink

<https://escholarship.org/uc/item/35m8q89f>

### Journal

Environmental Science and Technology, 52(22)

### ISSN

0013-936X

### Authors

Babacan, Oytun  
Abdulla, Ahmed  
Hanna, Ryan  
[et al.](#)

### Publication Date

2018-11-20

### DOI

10.1021/acs.est.8b03834

Peer reviewed

# Unintended Effects of Residential Energy Storage on Emissions from the Electric Power System

Oytun Babacan<sup>\*,1,2</sup>, Ahmed Abdulla<sup>1,2,3</sup>, Ryan Hanna<sup>1,2</sup>, Jan Kleissl<sup>2,3,4</sup> and David G. Victor<sup>1,2,5</sup>

<sup>1</sup> School of Global Policy and Strategy, University of California, San Diego, 9500 Gilman Drive, La Jolla, CA 92093, USA

<sup>2</sup> Deep Decarbonization Initiative, University of California, San Diego, 9500 Gilman Drive, La Jolla, CA 92093, USA

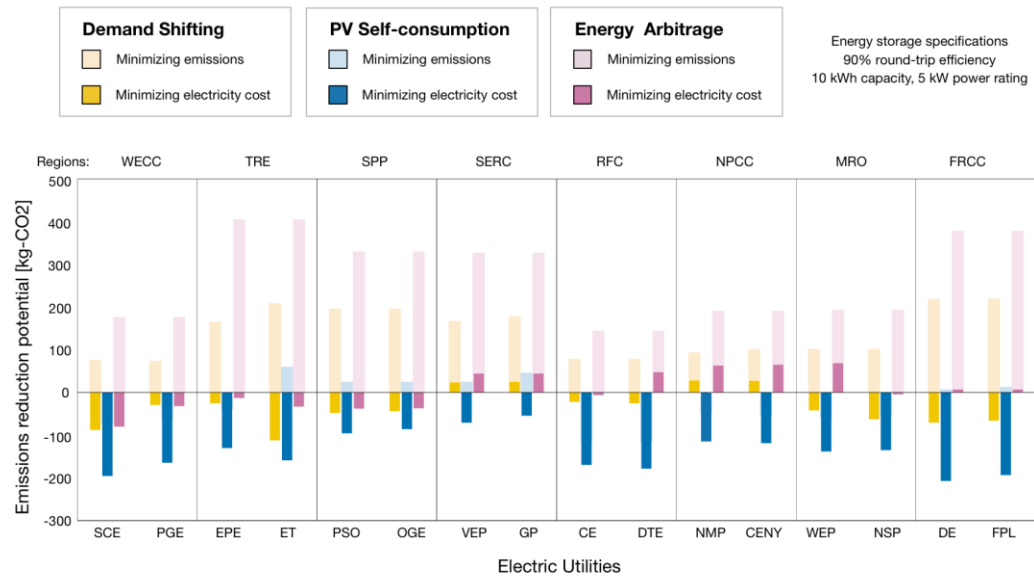
<sup>3</sup> Center for Energy Research, University of California, San Diego, 9500 Gilman Drive, La Jolla, CA 92093, USA

<sup>4</sup> Department of Mechanical and Aerospace Engineering, University of California, San Diego, 9500 Gilman Drive, La Jolla, CA 92093, USA

<sup>5</sup> The Brookings Institution, 1775 Massachusetts Avenue, NW, Washington, DC 20036, USA

\* Corresponding author e-mail address: oybabacan@ucsd.edu (O. Babacan)

## ABSTRACT:



In many jurisdictions, policy makers are seeking to decentralize the electric power system while also promoting deep reductions in emissions of greenhouse gases (GHG). We examine the potential roles for residential energy storage (RES), a technology thought to be at the epicenter of these twin revolutions. We model the impact of grid-connected RES operation on electricity costs and GHG emissions for households in 16 of the largest United States utility service territories under three plausible operational modes. Regardless of operation mode, RES mostly increases emissions when users seek to minimize their electricity cost. When operated with the goal of minimizing emissions, RES can reduce average household emissions by 2.2 – 6.4%, implying a cost equivalent of \$180 to \$5,160 per metric ton of carbon dioxide avoided. While RES is costly compared with many other emission control measures, tariffs that internalize the social cost of carbon would reduce emissions by 0.1 – 5.9% relative to cost-minimizing operation. Policy makers should be careful about assuming that decentralization will clean the electric power system, especially if it proceeds without carbon-mindful tariff reforms.

# 1 INTRODUCTION

2 The world must move to a deeply decarbonized energy system over the next several decades to avert the worst  
3 consequences of climate change.<sup>(1)-(2)</sup> Energy system analysts have laid out several potential pathways along  
4 which this transition might unfold,<sup>(3)</sup> and most suggest that cost-effective decarbonization will require massive  
5 electrification.<sup>(4)-(5)</sup> To provide this low-carbon electricity, many studies have focused on the role that renewable  
6 energy might play.<sup>(6)-(8)</sup> Policy makers have followed suit, promoting renewable energy as a strategy for  
7 decarbonization.<sup>(9)</sup>

8 At the same time, analysts have explored the benefits of an electric power system that is more decentralized,  
9 and policy makers in some jurisdictions, such as California and New York, are now actively promoting that  
10 future.<sup>(10)-(11)</sup> Many different political and technological forces are motivating interest in decentralization, such as  
11 the desire to empower consumers with greater control over their energy choices,<sup>(12)</sup> to create competition in a  
12 sector traditionally structured around regulated monopolies,<sup>(13)</sup> to defer costly investments in transmission  
13 infrastructure,<sup>(14)</sup> and to create conditions favorable to deployment of more rooftop solar photovoltaics (PV).<sup>(15)</sup>

14 Here we focus on the intersection of these two broad areas of academic and policy attention—the potential for  
15 simultaneous decarbonization and decentralization of the electric power system. We assess the role of behind-  
16 the-meter battery energy storage in the residential sector, which we refer to as residential energy storage (RES).  
17 While there has been significant and growing research on the economics and technical benefits of energy  
18 storage<sup>(16)-(17)</sup>—in particular in the context of decarbonized and decentralized power grids<sup>(18)</sup>—our study is  
19 focused squarely on the environmental issue: if consumers on their own or in response to policy pressure adopt  
20 these systems, will greenhouse gas emissions from the electric power system go down and at what economic cost?  
21 Here most analysis of the effects of energy storage on emissions has focused on the role of large-scale (megawatt)  
22 systems.<sup>(19)-(26)</sup> While a couple of these studies find emissions impacts of energy storage case dependent,<sup>(19)-(20)</sup>  
23 several report that revenue-maximizing energy storage operation tends to increase emissions of CO<sub>2</sub> and other  
24 pollutants in today's power systems.<sup>(21)-(23)</sup> On the other hand, several others report that system-wide integration  
25 of energy storage could reduce CO<sub>2</sub> emissions; by improving capacity utilization of renewable generators,<sup>(24)</sup> by

26 enabling a shift from coal-fired to gas-fired generation and reducing wind curtailment,<sup>(25)</sup> and if some form of  
27 carbon pricing framework can be established.<sup>(26)</sup> Beyond assessment of large-scale systems, several studies have  
28 also investigated the emissions effects of deploying storage technologies at the grid edge, notably in the  
29 commercial and industrial (C&I) sector.<sup>(27)-(28)</sup> Similar to the case in large-scale systems, increased CO<sub>2</sub> emissions  
30 from the grid have been observed when customers in the C&I sector operate energy storage under current tariff  
31 conditions for cost minimization.<sup>(27)</sup> However, certain C&I implementations of energy storage, e.g. when coupled  
32 with a combined power generation unit and an organic Rankine,<sup>(28)</sup> could potentially achieve emissions  
33 reductions. While the case for C&I customers deploying storage is strong under certain tariff regimes—notably  
34 when customers use these systems to reduce demand charges<sup>(29)</sup>—the vision of full grid decentralization hinges  
35 on more pervasive deployment of storage, including in residential settings. Assessing how RES systems would  
36 impact emissions is crucial since, in comparison to C&I customers, residential households have different power  
37 consumption behavior, they are subject to different electricity prices, and they own much smaller systems. Yet  
38 the analytical literature in this domain has lagged far behind the visions for grid transformation. Existing research  
39 has assessed how different residential tariff structures might affect energy bills<sup>(30)</sup> or energy consumption,<sup>(31)</sup> and  
40 associated CO<sub>2</sub> emissions. A couple of other studies has examined how RES might impact emissions when  
41 operated in modes that maximize self-consumption of PV generation in Texas, the United States (U.S.),<sup>(32)</sup> and at  
42 two locations in the United Kingdom.<sup>(33)</sup> Currently there is a lack of analysis on how the wider range of possible  
43 RES operation modes could affect emissions. There is also a lack of geographical coverage generally among  
44 studies. This study aims to fill these gaps.

45 This study offers the first comparative analysis of the emissions impact of RES under three realistic modes of  
46 operation that span the range of plausible near-future options: demand shifting, PV self-consumption, and energy  
47 arbitrage. The analysis samples 16 of the largest U.S. electric utilities in all eight of the regional grids in the  
48 continental U.S. Using real electric tariff and marginal emissions data, we calculate the emissions effects from  
49 RES deployment in these different modes. We also calculate what households would need to be paid to shift RES  
50 operation from a goal of minimizing electricity costs to one of minimizing emissions—a calculation that reveals  
51 the shadow level of carbon pricing that can then be compared against the cost of other mitigation options.

## 52 DATA AND METHODS

53 We formulate a convex optimization problem that determines optimal operation for RES that minimizes either  
54 household electricity costs or emissions. Solving these problems requires information about local electricity  
55 prices, household load profiles, and solar PV generation. Solving the emission minimization problem also requires  
56 knowing grid marginal emissions factors. To address these daunting data challenges, we first build a  
57 representative sample of a large cross-section of U.S. retail customers covering all eight of the major grid regions  
58 in the U.S., known as North America Electric Reliability Corporation (NERC) regions (see Table S-1 for region  
59 abbreviations). We select the two utility service territories that are largest by customer size within each of the  
60 eight NERC regions<sup>(34)</sup> (herein called region-territories)—for a total of 16 region-territories.

61 Electricity is supplied to the majority of households in the U.S. by investor-owned or publicly-owned utilities  
62 at prices approved by state regulatory commissions. Supplied electricity differs by price, which varies by utility,  
63 as well as bulk grid emissions, which vary by NERC region. Within each region-territory, we collect utility  
64 electricity prices as reported in time-of-use (TOU) tariff schedules and applicable adjustments, allowing us to  
65 model households' electricity costs depending on time of day, season, and location. In two NERC regions (TRE  
66 and RFC), the largest utilities do not offer a TOU tariff, so we choose the next largest utility in the region that  
67 does (see Table S-2).

68 Emissions due to electricity generation vary with location and time as the type of power plants activated to  
69 supply the marginal amount of energy needed changes. We take seasonal hourly grid marginal emissions in 2016  
70 from real-world conditions reported in the literature.<sup>(35)-(36)</sup> These emissions estimates are based on an analysis of  
71 hourly historic emissions and generation data from the Environmental Protection Agency's (EPA) Continuous  
72 Emissions Monitoring System (CEMS). We use these estimates to calculate changes in emissions caused by RES  
73 systems as they alter demand (and thus the emissions intensity of electricity generation that is needed to meet that  
74 demand).

75 We use prototypical residential load profiles provided by the U.S. Department of Energy<sup>(37)</sup> which are publicly  
76 available. Household consumption is reported as load profiles—i.e., annual consumption with one-hour time

77 step—that are the simulated electrical consumption of an archetypal house model built to the 2009 International  
78 Energy Conservation Code (IECC) as well as other standards related to domestic appliances, lighting and  
79 miscellaneous electric loads<sup>(38)</sup>. Load profiles are simulated considering different climatic conditions at typical  
80 meteorological year version 3 (TMY3) weather station locations<sup>(39)</sup> across the U.S.. These characterize hourly  
81 meteorological conditions from data collected over several decades. We use the subset of TMY3 sites—and  
82 associated unique household load profiles—available within each region-territory (220 in total; see Table S-3).

83 TMY3 data also underlie PV generation estimation for households with solar PV systems. The power output of  
84 each PV system is determined using a PV performance model<sup>(40)</sup> that calculates power generation as a function  
85 of solar irradiance, ambient air temperature, and wind speed data. Typical system parameters (Table S-4) are  
86 determined using the National Renewable Energy Laboratory’s PVWatts tool (<http://pvwatts.nrel.gov>). Each PV  
87 system, regardless of household location, has a 5.35 kW rating, which is the average capacity installed across the  
88 region-territories under consideration (see Table S-5).

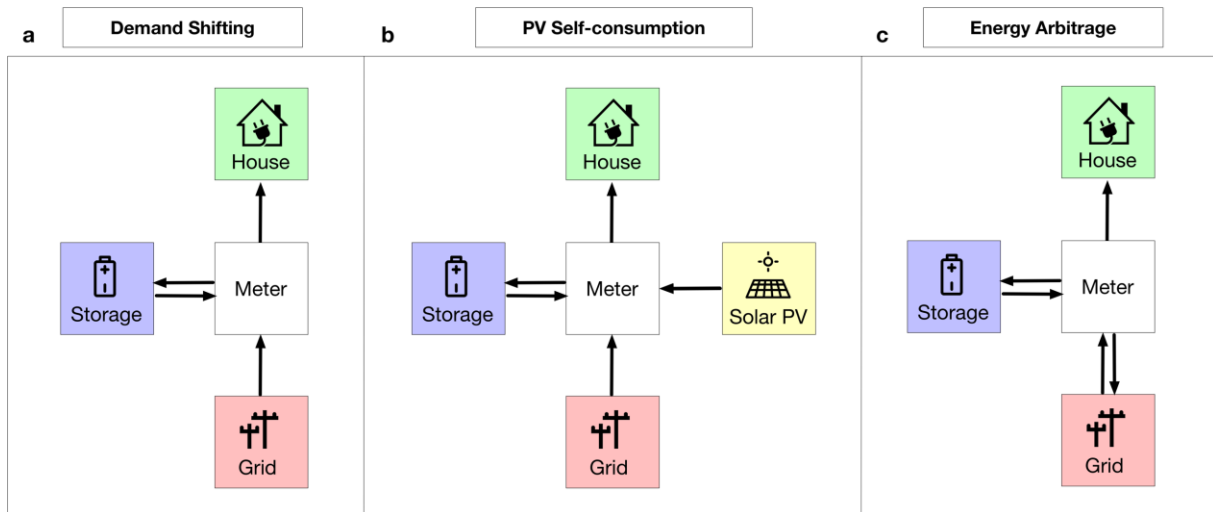
89 We calculate optimal RES dispatch profiles for a full year of operation (8760 hours) with two different objective  
90 functions. First, households operate RES systems to minimize household electricity costs, which is the  
91 economically rational choice. With this same goal to minimize cost, we further model a variant that adds the  
92 social cost of carbon (SCC) to the electricity cost, estimated today at \$46 in 2017 dollars per emission of metric  
93 ton of CO<sub>2</sub><sup>(41)</sup>. Adding the SCC to electricity prices reveals the behavioral response of customers that internalize  
94 the carbon costs of their energy choices—independent of whether that carbon is emitted locally or from the grid.  
95 Under the second objective function, customers use RES to minimize emissions regardless of cost—which reveals  
96 the maximum potential for emissions reductions via RES.

97 **Three modes of operation for households.** The cost and effect on emissions of achieving these two goals  
98 depends on how households operate their RES devices. We look at three modes of operation (Figure 1). These  
99 modes of operation are treated as constraints on RES systems regardless of the objective functions we describe  
100 above. First, households can use their RES as demand shifting systems, in which RES systems shift the time of  
101 household electricity demand and minimize electricity costs under a variable TOU tariff. In this mode, households  
102 find the lowest cost for purchasing power, but they do not sell electricity back to the grid. This form of demand

103 management is currently available in every state and utility with a TOU tariff program. Residential households  
104 have historically been charged via flat volumetric rates and thus have had no incentive to shift demand. Though  
105 some utilities have offered opt-in TOU tariffs, few households have made the move<sup>(42)</sup>. That is now changing as  
106 regulators consider mandatory TOU tariffs as part of an attempt to better capture the time-varying costs of  
107 electricity generation. In California, for example, the default residential tariff will switch to TOU for all  
108 households served by the major investor owned utilities beginning in 2019<sup>(43)</sup>. Furthermore, our survey on  
109 residential tariff options among 562 utilities in 2017 shows that TOU tariffs are currently being offered to  
110 residential customers in 46 of the 48 contiguous U.S. even though their uptake across states varies.

111 In the second mode of operation, which we term the PV self-consumption mode, households that have installed  
112 PV systems use RES to maximize the self-consumption of their solar PV electricity. At present, there is little  
113 incentive to use batteries in this way because nearly all states have net metering programs that credit excess power  
114 sent to the grid at retail rates. However, new proposals to alter compensation schemes for excess generation<sup>(44)</sup>-  
115 <sup>(45)</sup>, or prohibit net metering altogether<sup>(46)</sup>, would erode or eliminate the benefits of energy sales, which could  
116 encourage RES deployment in households with PV systems and also encourage these households to operate their  
117 RES devices to maximize PV self-consumption. We compare RES operated in this mode against a baseline  
118 without RES but that includes a PV system that is net metered, the default mode of operation today in the U.S.  
119 for most solar PV system owners.

120 Finally, in the third mode of operation, households with RES systems engage in two-way energy arbitrage,  
121 buying and selling electricity at retail rates to maximize revenue. This mode, while futuristic and quite demanding  
122 of local infrastructure and control systems, reflects the vision of advocates of decentralized energy management.  
123 Several U.S. states are currently exploring whether to allow households to exploit RES systems in this way<sup>(47)</sup>-  
124 <sup>(49)</sup>. The logic for this mode is also reflected, partly, in proposals for distributed locational marginal prices that  
125 are designed to encourage more local arbitrage and demand response<sup>(50)</sup>. Logically, that same kind of arbitrage  
126 could extend to residential customers, albeit at a smaller scale.



**Figure 1 | Modes of operation for residential energy storage (RES) at households: (a) demand shifting, (b) PV self-consumption, and (c) energy arbitrage.** Arrows indicate direction of power flow. Demand shifting is the simplest mode. PV self-consumption extends demand shifting by adding a PV system to the household. Energy arbitrage extends demand shifting by allowing energy back-flow to the grid. Table S-6 shows the baseline configurations for each mode of operation.

We assume each household adopts RES with a capacity of 10 kWh and a charging/discharging limit of 5 kW. This is in alignment with capacities typically offered by RES vendors, such as in the Tesla Powerwall, sonnenBatterie eco, and Evolve RES system (websites accessed April 2018). The 5-kW rating is sufficiently large to absorb peak solar PV generation or deliver maximum electricity demand for all modes considered in this study. In other words, RES system size is not a limiting factor in energy storage system scheduling, whether operation is intended to shift demand, self-consume PV generation, or engage in energy arbitrage (Sensitivity of the results to different system sizes is provided in the Supplementary Information).

**Household energy balance.** We model the household, RES, and, when present, solar PV system, at a single node behind the electricity meter of the customer. The power balance equation for household net demand  $p(k)$  at the electricity meter is given by

$$p(k) = l(k) - g(k) + c(k) - u(k) \quad (1)$$



138 where the time step  $k \in \{1, \dots, s\}$  and  $s$  is the number of time steps in a day-long charging schedule. If  $\Delta t$  is the  
139 time-interval between consecutive time-steps  $k$ , then  $s = 24h/\Delta t$ . The average demand of the household over a  
140 period  $\Delta t$  is  $l(k)$ . Similarly, the average solar generation is  $g(k)$ , the average curtailed solar PV generation is  $c(k)$ ,  
141 and the average RES charge/discharge is  $u(k)$ . All units are in kW. The variable  $u$  is positive while discharging.  
142 Net demand  $p(k)$  is the demand seen by the utility and is positive when power is flowing from the grid to the  
143 household. Similarly, curtailment  $c(k)$  is positive.

144 We modify variables in Equation 1 depending on the mode of operation. For modes without a solar PV system,  
145 solar generation  $g(k)$  and curtailed solar generation  $c(k)$  are zero for all time steps. For the energy arbitrage mode,  
146 net demand  $p(k)$  may be negative or positive, but for the demand shifting and the PV self-consumption modes,  
147 net demand  $p(k)$  is constrained to be nonnegative for all time steps because energy sales are prohibited in these  
148 modes. For the PV self-consumption mode, curtailed solar generation  $c(k)$  is equivalent to the excess solar  
149 generation that would have ordinarily been injected into the grid. In this case, it does not result in financial  
150 compensation to the customer.

151 In all scenarios, we use the observed data to be the day-ahead forecasts for demand  $l(k)$  and solar generation  
152  $g(k)$  of each household, which is an assumption of perfect information. Though in practice real forecasts with  
153 some error would be used operationally, in this study we assume perfect forecasts to model the upper limit of  
154 RES performance, as is commonly done in the literature<sup>(32)</sup>.

155 **RES model.** The rated energy capacity of the RES is represented by  $C$  in kWh. We set the initial state of charge  
156 (SOC)  $\chi(0)$  to 50% of the rated energy capacity  $C$ . We define the minimum allowed SOC and the maximum  
157 allowed SOC of the RES in kWh as  $\underline{\chi}$  and  $\bar{\chi}$ , where  $\underline{\chi} := 0$  and  $\bar{\chi} := C$ . We assume here that degradation is  
158 negligible to model the upper limit of RES performance (Sensitivity to degradation is provided in the  
159 Supplementary Information). The relation governing SOC is then given by  $\chi(k) = \chi(0) - \sum_{k=1}^s u(k)\Delta t$ . The  
160 RES charge/discharge  $u(k)$  consists of  $u_{\text{chg}}(k)$  and  $u_{\text{dchg}}(k)$ . The RES charge  $u_{\text{chg}}(k)$  is constrained by  $0 \leq$   
161  $|u_{\text{chg}}(k)| \leq \bar{u}$  and the RES discharge  $0 \leq u_{\text{dchg}}(k) \leq \underline{u}$ , where  $\underline{u}$  and  $\bar{u}$  are the discharge and charge power  
162 limit of RES, respectively. Following the literature<sup>(21),(26)</sup>, we consider storage inefficiencies  $\eta_{\text{rt}}$  by dividing the

total energy lost during charging and discharging equally between the charge and discharge cycles. Whenever the RES charges, we assume that its SOC increases by  $\eta_{rt}^{1/2} u_{chg}(k)$ . Similarly, when the RES discharges, its SOC decreases by  $\eta_{rt}^{-1/2} u_{dchg}(k)$ .

**RES scheduling.** A convex optimization approach is taken to determine the optimal RES scheduling for each household. We code the scripts for the optimization problem using MATLAB (Version 2016b) and solve it using the convex modeling framework CVX (Version 2.1) and the solver Gurobi (Version 7.0.2). The formulation of the optimization problem builds on previous work<sup>(51)</sup>. In the following formulation, we denote vectors in bold. RES is dispatched daily following the convex optimization problem:

$$\min_{\mathbf{p} \in \mathbb{R}^S} \Delta t \boldsymbol{\phi} \mathbf{p} \quad (2)$$

where  $\mathbf{p}$  is the household net demand and  $\boldsymbol{\phi}$  is the cost factor that is dependent on the objective under consideration. The objectives and associated cost vectors are defined as: (1) Minimizing household electricity cost  $\boldsymbol{\phi} = \boldsymbol{\Lambda}$ , where  $\boldsymbol{\Lambda}$  is the TOU tariff that consists of pricing blocks; (2) Minimizing household electricity cost while internalizing the social cost of carbon  $\boldsymbol{\phi} = \boldsymbol{\Lambda} + \lambda_c \cdot \mathbf{ME}$ , where  $\lambda_c$  is the current social cost of carbon estimate and  $\mathbf{ME}$  is hourly marginal emission estimates of each day; and (3) Minimizing emissions  $\boldsymbol{\phi} = \mathbf{ME}$ . The social cost of carbon  $\lambda_c$  is taken as \$46 in 2017 dollars per metric ton of CO<sub>2</sub>, which equates to \$38.4 in 2007 dollars per metric ton of CO<sub>2</sub>. We use an inflation rate of 1.67% per year to determine the estimates for 2017.

The optimization problem is subject to an inequality constraint that describes the RES charge and discharge limits, capacity constraints, the SOC dynamics, and to an equality constraint that prevents energy-shifting between days. The inequality constraint  $\mathbf{A}\mathbf{u} \leq \mathbf{b}$  represents the dynamics of the energy storage model described above. Its definition follows the derivation given in the literature<sup>(52)</sup> except here we also consider storage inefficiencies as described earlier. The equality constraint  $\mathbf{1}\mathbf{u} = 0$ , where  $\mathbf{1}$  is the all-1 row vector, ensures that  $\chi(s)$ , the final SOC at the end of each day (at time  $s\Delta t$ ), equals the initial SOC  $\chi(0)$  and hence prevents the RES from passing energy from one day to the next. The optimization horizon is one day, and RES are scheduled to minimize the objective over that horizon (See Figure S-1 and S-2).

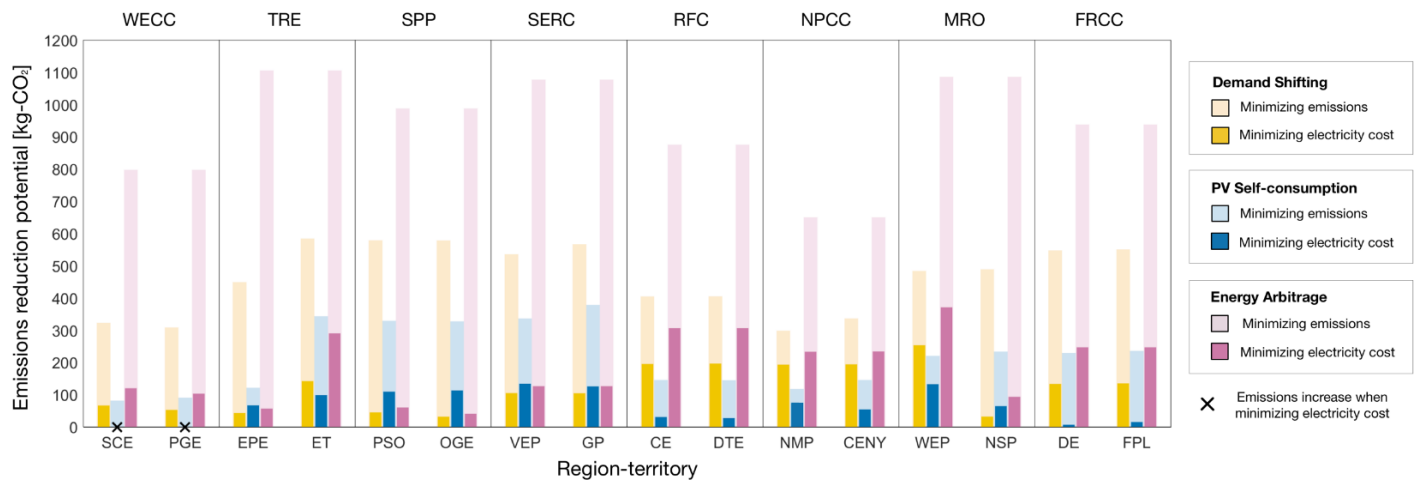
187 **Estimating RES impacts on cost and emissions.** To estimate the impact of deploying RES on operating  
188 costs and emissions we first calculate a baseline (see Table S-6) where households neither own RES nor PV (with  
189 the exception of PV self-consumption). For that baseline, electricity costs and emissions are a function solely of  
190 the hourly household electricity consumption. Each household is billed monthly based on their kWh electricity  
191 consumption via TOU pricing. Similar to the literature<sup>(21),(26),(32)</sup> we estimate the cost impact of RES by comparing  
192 the baseline electricity bill of each household (i.e., without RES) with their electricity bill with RES. Whenever  
193 RES shifts the net demand seen by the bulk grid, the associated change in grid emissions is calculated by  
194 multiplying the consumption increase or decrease by the applicable marginal emissions at that hour.

## 195 **RESULTS**

196 We first evaluate the maximum potential impact on emissions and costs from RES systems by considering  
197 idealized lossless RES systems, which is a helpful benchmark before adding real-world operational considerations  
198 in the next section.

199 Figure 2 shows the emissions reduction potential for RES systems deployed across the 16 region-territories  
200 under each of two goals: minimizing electricity cost (bold bars) and minimizing emissions (light bars). Regional  
201 variation in emissions reduction potential reflects the variation in marginal emissions across the eight different  
202 national grids. For instance, achievable emissions reductions within Texas (TRE), where marginal generators  
203 have higher emissions during morning hours when coal is a significant source of marginal generation, are roughly  
204 double that in the Northeastern U.S. (NPCC), where temporal variations in emissions throughout the day are much  
205 smaller since gas-fired generators are always dominant on the margin (see Figure S-5).

206 There is also a substantial difference between objective functions that minimize costs and emissions. Though  
207 lossless RES systems are almost always capable of reducing emissions when they are operated in ways that  
208 minimize cost, that reduction is relatively small. On the other hand, when RES systems are configured to minimize  
209 emissions via energy arbitrage (pink bars), they have, on average, about an eight-fold higher reduction potential  
210 than when configured to reduce cost.



**Figure 2 | Potential annual household emissions reductions with a lossless RES system in different modes of operation.** NERC regions are shown along the top, with the two selected utilities in each region shown along the bottom. The bars show mean of maximum annual emissions reductions achieved by all households in each region-territory under each of three modes of operation. For each mode of operation, we model two distinct objectives: minimizing electricity cost (dark bars) or minimizing emissions (light bars). Even when RES is assumed lossless (as shown here), two cases (in WECC) still lead to emissions increases when households minimize electricity cost. Such cases become more common when the same calculations are repeated considering battery inefficiencies (see Figures S-3 and S-4).

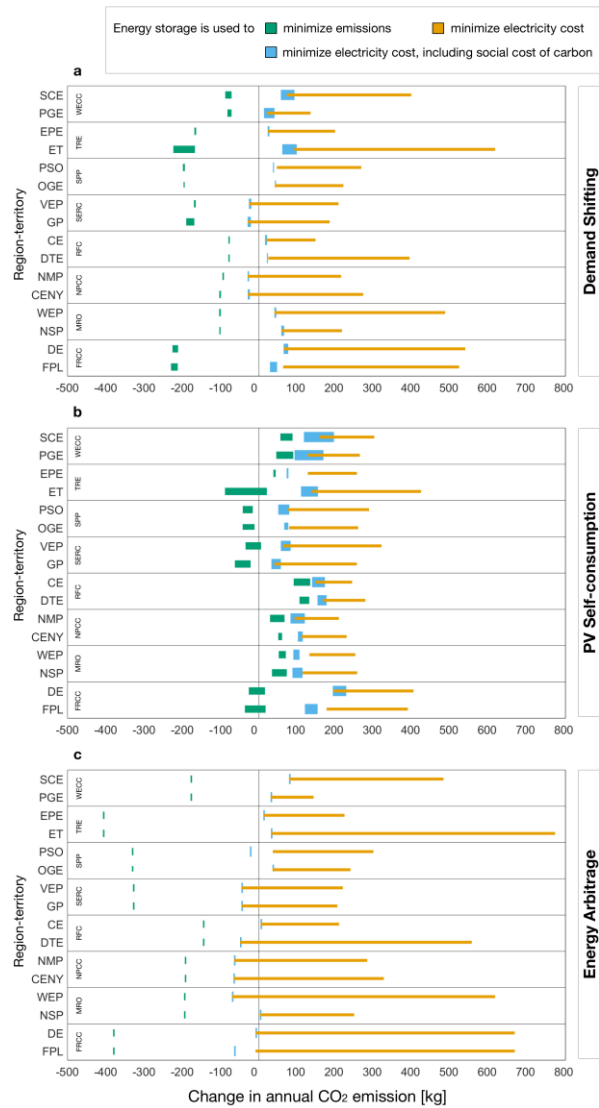
At least two implications follow from the analysis of the maximum potential impact on emissions. First, while much policy attention has focused on promoting PV self-consumption mainly for reasons of managing reverse power flows, this mode has the lowest effect on emissions reductions in every region-territory. Our work suggests that energy arbitrage could be most effective at reducing emissions. Second, variation in the tariff structure within a single NERC region (that is, interconnected grids with common marginal emissions) has a strong impact on emissions under different RES modes. Each pair of region-territories within a given NERC region has an identical potential to reduce emissions from energy arbitrage (see light pink bars). In contrast, where tariff structures differ across the utilities within a given NERC region, the expected emissions reductions if customers minimize electricity costs (see dark bars) differ significantly—most saliently for Texas (TRE) and the Midwest (MRO). Another striking example is observed in the Midwest (MRO) among households using RES for demand shifting,

221 where the emissions reductions achieved in Wisconsin (WEP) are over eight times higher than in Minnesota  
222 (NSP). This is driven by differences in tariff structures, including the duration, timing, and seasonality of peak  
223 pricing. Ultimately, it shows that reduction potentials are maximized when tariffs align favorably with marginal  
224 emission rates.

225 **Cost of using residential energy storage to reduce emissions.** We now transition from an analysis  
226 of maximum potentials, which assumes that RES systems are lossless, to more realistic conditions that assume  
227 90% battery round-trip efficiency, typical of top-performing lithium-ion battery systems deployed today<sup>(53)</sup>. The  
228 main effect of adding battery inefficiencies is to increase emissions; losses increase energy consumption that  
229 mainly comes from fossil fuels<sup>(36)</sup>.

230 Figure 3 shows the change in annual household emissions when households operate RES systems under each  
231 of the three operating modes to minimize electricity costs (orange bars), minimize electricity costs that embed the  
232 social cost of carbon (blue bars), or minimize emissions regardless of cost (green bars). Within each bar lies the  
233 annual change in emissions estimates reported for each household. Orange bars further report the full range of  
234 possible annual change in emissions when RES systems are operated to minimize electricity. There is considerable  
235 variation in cost minimal operation (orange bars) because utility TOU tariffs are built on pricing blocks—i.e.,  
236 periods of constant pricing—that last several hours. RES systems can operate along multiple different pathways  
237 within pricing blocks that minimize costs equally. Since marginal emissions vary within those TOU pricing  
238 blocks, each potential pathway has a different emissions footprint. Absent incentives to lower emissions, a large  
239 range of emissions can result from RES operation—as denoted by the orange bars. Different meteorological  
240 conditions contribute further variability for different households in a region-territory, albeit to a lower degree.

241 Three points emerge from the analysis in Figure 3. First, in each of the three modes, nearly the full range of  
242 possible outcomes for cost minimization (orange bars) involves an increase in emissions. That range of emission  
243 impacts is larger, slightly, in energy arbitrage mode—reflecting a wider range of possible outcomes when  
244 households can move power in both directions with the grid. More importantly, while maximizing



**Figure 3 | Impact on annual household emissions of using RES for (a) demand shifting, (b) PV self-consumption, and (c) energy arbitrage.** For each mode of operation, we model three different objectives: minimizing electricity costs (orange bars), minimizing electricity costs that include the social cost of carbon (blue bars), and maximizing emissions reductions regardless of cost (green bars). Top (a) and bottom (c) charts show change in emissions relative to average household electricity emissions without a PV or RES system. In the PV self-consumption mode (b), change in emissions is determined relative to equivalent households equipped with a net-metered solar PV system without a RES system. Blue and green bars show the range of estimates while orange bar shows all possibilities in emissions impact during a cost-minimal energy storage operation by all households in each region-territory.

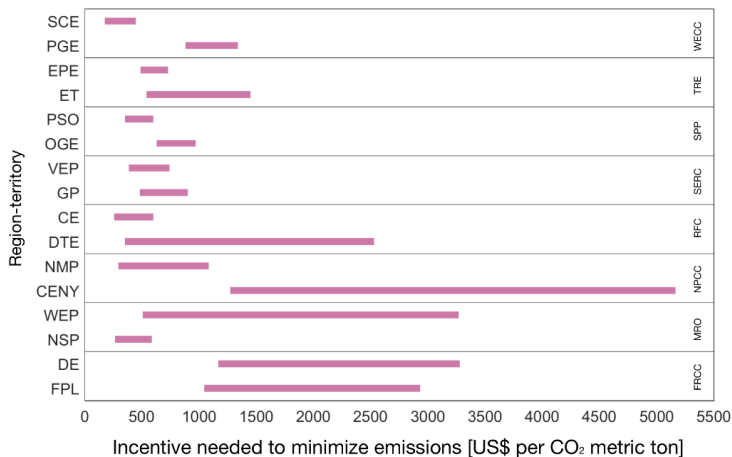
PV self-consumption, no household is able to reduce emissions compared to an equivalent household that lacks RES and has installed PV with traditional net metering. These results suggest that the outcome from tariff reforms aimed at boosting residential PV self-consumption—for example, the new settlement in Arizona<sup>(54)</sup> that introduces a self-consumption reimbursement rate that closely matches current export rates for excess PV generation—will be contrary to the emission impacts that PV advocates have been seeking.

Second, adding incentives to internalize the cost of emissions (here, in the form of a carbon price) significantly reduces variation in the range of potential emissions impacts (blue bars have on average, among all modes of operation, one-tenth of the variation compared to the orange bars). A carbon price mainly shifts RES operation within a TOU pricing block (at essentially no cost) to the times that are most beneficial for emissions. As higher carbon prices would be implemented, RES would be committed more to reducing emissions directly. But under the SCC, the savings from minimizing electricity costs far exceed the gains from avoiding emissions: the largest average annual savings from reducing emissions—those of RES operating in energy arbitrage mode at the rightmost point of the orange bars in ET (Texas)—are less than \$35 (i.e., the SCC multiplied by the emissions savings obtained by moving from the orange bars to the blue bars), whereas the average annual savings in electricity costs are more than \$400. Nevertheless, if households responded to a carbon price equivalent to the SCC, average household emissions across all region-territories would decrease, on average, by 0.1 – 3.9% when demand shifting, 0.3 – 2.0% when maximizing PV self-consumption, and 0.1 – 5.9% when engaging in energy arbitrage compared with RES operation that ignores the cost of emissions (In effect, shifting from the orange bars to the blue bars)

Third, only when RES systems are forced to minimize emissions—in effect, when the carbon price is impractically high—do they succeed in reducing emissions across all regions. Compared to the baseline, reductions reach 1.0 to 3.0% while demand shifting, 2.2 to 6.4% during energy arbitrage, and up to almost 0.9% when they maximize PV self-consumption (see Figure S-6). RES used to maximize PV self-consumption still mostly increase emissions; the southeastern (SERC) and southern (SPP) parts of the U.S. are exceptions. This is because the baseline condition (residential PV with net metering) provides zero-emission solar energy to the grid

270 during relatively high emission hours in all other region-territories. For PV self-consumption, emissions only  
271 decline in grids with relatively low marginal emissions during peak solar hours.

272 Contrasting the two objectives—minimizing electricity cost and minimizing emissions—helps us evaluate the  
273 incentives that might be needed to encourage emissions reductions via RES. Figure 4 shows the annual total that  
274 utilities would have to pay households to reimburse economic losses they would experience when they operate  
275 with the goal of minimizing emissions instead of cost. These annual totals are derived by taking the difference in  
276 net revenue under both cost minimization and emissions minimization scenarios, then dividing this value by  
277 differences in net emissions under both cases. On average, this shift from cost minimization to emissions  
278 minimization allows households to reduce their annual emissions from electricity consumption by 6.8% or 460  
279 CO<sub>2</sub>-kg (the amount of CO<sub>2</sub> emissions from about 52 gallons of gasoline consumed<sup>(55)</sup>), and in several regions  
280 (Texas and Florida—TRE and FRCC) annual reductions of more than 1,000 CO<sub>2</sub>-kg are achievable (See Figure  
281 S-7). Even where reductions are significant, the associated cost of shifting to this objective is extremely high,  
282 averaging \$1,100 per metric ton of CO<sub>2</sub> emissions reduced.



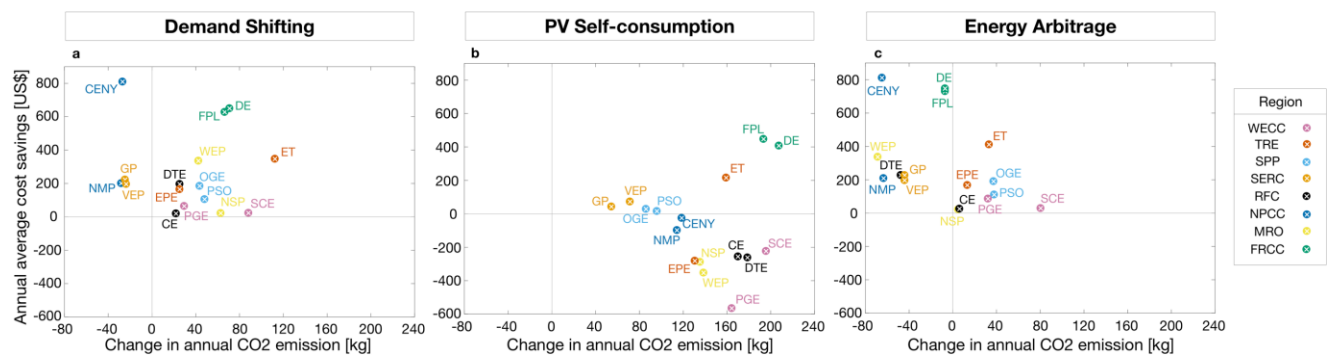
**Figure 4 | Carbon prices needed to achieve maximum emissions reduction under energy arbitrage.**

Shown are the range of prices that would need to be offered to households for operating their RES systems to minimize emissions rather than the cost of electricity during energy arbitrage. Under existing tariff structures, the cost of such interventions is high—much higher than current estimates for the social cost of carbon (\$46 per metric ton of CO<sub>2</sub>).



283 Variation in the incentives needed to minimize emissions across region-territories is high—from \$180 to  
 284 \$5,160—and mainly reflects variation in the ratio of on-peak and off-peak energy prices in each region-territory.  
 285 Households with RES can achieve larger electricity cost reductions where that ratio is higher—because they can  
 286 shift demand between larger price differences. For instance, there is a 10-fold difference in incentives needed  
 287 between the utilities of CE and DTE (both in RFC) even though they implement the same peak pricing duration,  
 288 timing, and seasonality (see Figure S-5). Households in DTE (where the ratio of on-peak to off-peak pricing per  
 289 kWh is 23% greater than CE) gain more from operating their RES in an economically rational way, which makes  
 290 it much costlier to implement incentives that encourage emissions reductions in this region-territory. We doubt  
 291 that tariff planners intended these effects, but currently there is a huge imbalance in the cost of emission control  
 292 through RES.

293 In Figure 5, we summarize annual cost savings and associated changes in annual CO2 emissions when  
 294 households deploy RES systems to minimize their electricity costs. The energy arbitrage mode is most effective  
 295 at achieving the dual benefits of reducing electricity cost and emissions: eight out of the 16 region-territories  
 296 succeed in doing so. In the demand shifting mode, only four of the 16 region-territories achieve both cost and



**Figure 5 | Annual change in household savings and emissions when operating RES under demand shifting (a), PV self-consumption (b), and energy arbitrage (c).** Savings and the best-case emissions reduction (leftmost side of the orange bars in Figure 3) are averaged across all households in a region. Only rarely do RES systems simultaneously achieve cost reductions and emissions reductions (graphically, the upper left quadrant).

emissions reductions. Meanwhile, the PV self-consumption mode is unable to reduce emissions and costs simultaneously in any of the locations.

## DISCUSSION

Energy storage is widely expected to play an integral role in efforts to deeply decarbonize the electric power system. It is expected that energy storage will help integrate distributed renewable energy resources like rooftop solar PV systems, while also providing substantial operational flexibility for grid operators. Most households adopting energy storage are likely to choose equipment vendors and operation modes that allow them to minimize electricity costs. We show that, indeed, the deployment of energy storage in the residential sector can help reduce household electricity bills, but that RES will also generally lead to higher emissions. Encouraging households to temper this increase in emissions could be relatively inexpensive if done with a carbon tax but operating RES for the goal of reducing emissions is exceptionally costly. There may be good reasons to decentralize the grid through ubiquitous installation of small RES, but cost-effective emissions control is not one of them at the moment.

An especially helpful way for policy-makers to encourage RES adoption while reducing its adverse impacts on emissions lies with reform of utility tariff structures, which are the primary reason emissions reductions do not typically follow cost reductions. Tariffs that better reflect wholesale electricity prices and the cost of emissions could prompt simultaneous emissions and cost reductions. In grids with low penetration of renewables, the effect of these tariff reforms could be minimal, but in grids where penetration is much higher, the impacts could be significant and merit analysis. More work is needed to understand whether such alignment could be implemented and at what cost.

Absent substantial tariff reform, policy-makers could still encourage environmentally beneficial RES operation by ensuring that system developers and equipment vendors favor clean energy use by tracking and adjusting to variations in marginal emissions of the bulk grid. Some of this work is already underway by third-party groups<sup>(56)</sup>.

There is much interest and enthusiasm for transformation of the electric power grid—and with that, transformation of the whole energy system<sup>(57)</sup>. Enthusiasm, however, is no substitute for analysis, and there could be many unintended consequences from rapid large scale technological changes<sup>(21),(27),(32)</sup>. Decentralization of the

322 grid could become a cauldron of unintended consequences—including for emissions of the gases that cause  
323 climate change. It will be the role of policy-makers and regulators to put in place mechanisms, like new tariffs,  
324 that ensure that this transformation benefits both households and society in terms of cost savings and emissions  
325 reductions.

## 326 **ASSOCIATED CONTENT**

### 327 **Supplementary Information.**

328 Detailed information about electric utilities, utility rate codes and applicable riders, TMY3 weather sites  
329 considered in the study, schematics explaining each mode and baseline configuration, sample RES  
330 dispatch figures, figures showing sensitivity on battery round-trip efficiency, battery degradation, battery  
331 system size, and solar PV system size, figures showing relative impact on annual household emissions,  
332 figures showing mean hourly emissions estimates and peak electricity pricing periods.

## 333 **AUTHOR INFORMATION**

### 334 **Corresponding Author**

335 \* O. Babacan. Email: [oybabacan@ucsd.edu](mailto:oybabacan@ucsd.edu)

### 336 **ORCID**

337 Oytun Babacan: [0000-0001-9141-8872](https://orcid.org/0000-0001-9141-8872)

### 338 **Author contributions**

339 O.B. formulated the problem with contributions from all authors. O.B. wrote codes, conducted simulations, and  
340 created illustrations. All authors contributed to analyzing data and writing the manuscript.

### 341 **Notes**

342 The authors declare no competing financial interests.

## 343 **ACKNOWLEDGMENTS**

344 We thank E. Wilson (NREL) for his feedback on the residential load profiles data set.

## REFERENCES

- (1) Bruckner, T.; Bashmakov, I. A.; Mulugetta, Y.; Chum, H.; Vega Navarro, A. de la; Edmonds, J. ; Faaij, A.; Fungtammasan, B.; Garg, A.; Hertwich, E.; Honnery, D.; Infield, D.; Kainuma, M.; Khennas, S.; Kim, S.; Nimir, H. B.; Riahi, K.; Strachan, N.; Wisser, R.; Zhang, X. Energy Systems. In: *Climate Change 2014: Mitigation of climate change. contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC)*. Cambridge University Press, 2014.
- (2) Peters, G. P.; Andrew, R. M.; Solomon, S.; Friedlingstein, P. Measuring a fair and ambitious climate agreement using cumulative emissions. *Environmental Research Letters* **2015**, *10*, 105004; DOI 10.1088/1748-9326/10/10/105004.
- (3) Sisternes, F. J.; Jenkins, J. D.; Botterud, A. The value of energy storage in decarbonizing the electricity sector. *Applied Energy* **2016**, *175*, 368 – 379; DOI 10.1016/j.apenergy.2016.05.014.
- (4) Edenhofer, O.; Pichs-Madruga, R.; Sokona, Y.; Farahani, E.; Kadner, S.; Seyboth, K.; Adler, A.; Baum, I.; Brunner, S.; Eickemeier, P.; Kriemann, B.; Savolainen, J.; Schlömer, S.; von Stechow, C.; Zwickel, T.; Minx J. C. (Eds.) Summary for Policymakers. In: *Climate Change 2014: Mitigation of climate change. contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC)*. Cambridge University Press, 2014.
- (5) *U.S. National Electrification Assessment*; Report No. 3002013582; Electric Power Research Institute: Palo Alto, CA, 2018; <http://mydocs.epri.com/docs/PublicMeetingMaterials/ee/000000003002013582.pdf>.
- (6) Denholm, P.; King, J. C.; Kutcher, C. F.; Wilson, P. P. H. Decarbonizing the electric sector: Combining renewable and nuclear energy using thermal storage. *Energy Policy* **2012**, *44*, 301-311; DOI 10.1016/j.enpol.2012.01.055.
- (7) Attia, S. Net Zero Energy Buildings (NZEB). *Concepts Frameworks and Roadmap for Project Analysis and Implementation*; Butterworth-Heinemann: Oxford, U.K., 2018.
- (8) Raghavan, S. V.; Wei, M.; Kammen, D. M. Scenarios to decarbonize residential water heating in California. *Energy Policy* **2017**, *109*, 441-451; DOI 10.1016/j.enpol.2017.07.002.

370 (9) *2019 Standards Notice of Proposed Action*; Docket Number 17-BSTD-02; California Energy Commission:  
371 Sacramento, CA, 2018; <http://www.energy.ca.gov/>.

372 (10) *Proceedings on Motion of the Commission in Regard to Reforming the Energy Vision*; Case Number 14-M-  
373 0101; New York State Department of Public Service: New York, NY, 2014; <https://www.dps.ny.gov/>.

374 (11) *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative,*  
375 *the Self-Generation Incentive Program and Other Distributed Generation Issues*; Rulemaking 12-11-005;  
376 California Public Utility Commission: Sacramento, CA, 2012; <http://www.cpuc.ca.gov/>.

377 (12) *World Energy Trilemma: Changing Dynamics - Using Distributed Energy Resources to Meet the Trilemma*  
378 *Challenge*; World Energy Council: London, U.K., 2017; [https://www.worldenergy.org/wp-](https://www.worldenergy.org/wp-content/uploads/2017/11/World-Energy-Trilemma-2017_Full-report_WEB.pdf)  
379 [content/uploads/2017/11/World-Energy-Trilemma-2017\\_Full-report\\_WEB.pdf](https://www.worldenergy.org/wp-content/uploads/2017/11/World-Energy-Trilemma-2017_Full-report_WEB.pdf).

380 (13) *A level playing field for local energy*; Issues paper prepared for the City of Sydney; Institute for  
381 Sustainable Futures (UTS): Sydney, Australia, 2014;  
382 [https://www.uts.edu.au/sites/default/files/ISF\\_Level%20playing%20field%20for%20Local%20Energy\\_Nov201](https://www.uts.edu.au/sites/default/files/ISF_Level%20playing%20field%20for%20Local%20Energy_Nov2014.pdf)  
383 [4.pdf](https://www.uts.edu.au/sites/default/files/ISF_Level%20playing%20field%20for%20Local%20Energy_Nov2014.pdf).

384 (14) *Energy Storage for Transmission and Distribution Deferral*; Navigant Research: Washington, DC, 2017;  
385 <https://www.navigantresearch.com/reports/energy-storage-for-transmission-and-distribution-deferral>.

386 (15) *Energy Storage Requirements for Achieving 50% Solar Photovoltaic Energy Penetration in California*;  
387 NREL/TP-6A20-66595; National Renewable Energy Laboratory: Golden, CO, 2016;  
388 <https://www.nrel.gov/docs/fy16osti/66595.pdf>.

389 (16) *The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most*  
390 *services and value to customers and the grid*; Rocky Mountain Institute: Boulder, CO, 2015; [https://rmi.org/wp-](https://rmi.org/wp-content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf)  
391 [content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf](https://rmi.org/wp-content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf).

392 (17) *The Role of Energy Storage with Renewable Electricity Generation*; NREL/TP-6A2-47187; National  
393 Renewable Energy Laboratory: Golden, CO, 2010; <https://www.nrel.gov/docs/fy10osti/47187.pdf>.

394 (18) *Development of decentralised energy and storage systems in the UK*; KPMG LLP: U.K., 2016;  
395 [http://www.r-e-a.net/upload/rea\\_storage\\_report-web\\_accessible.pdf](http://www.r-e-a.net/upload/rea_storage_report-web_accessible.pdf).

- 396 (19) Arbabzadeh, M.; Johnson, J. X.; Keoleian, G. A. Parameters driving environmental performance of energy  
397 storage across grid applications. *Journal of Energy Storage* **2017**, *12*, 11-28; DOI 10.1016/j.est.2017.03.011.
- 398 (20) Lin, Y.; Johnson, J. X.; Mathieu, J. L. Emissions impacts of using energy storage for power system reserves.  
399 *Applied Energy* **2016**, *168*, 444-456; DOI 10.1016/j.apenergy.2016.01.061.
- 400 (21) Hittinger, E. S.; Azevedo, I. M. L. Bulk energy storage increases United States electricity system emissions.  
401 *Environmental Science & Technology* **2015**, *49* (5), 3203-3210; DOI 10.1021/es505027p.
- 402 (22) Lueken, R.; Apt, J. The effects of bulk electricity storage on the PJM market. *Energy System* **2014**, *5* (4),  
403 677-704; DOI 10.1007/s12667-014-0123-7.
- 404 (23) Carson, R. T.; Novan, K. The private and social economics of bulk electricity storage. *Journal of*  
405 *Environmental Economics and Management* **2013**, *66* (3), 404-423; DOI 10.1016/j.jeem.2013.06.002.
- 406 (24) Khalilpour, K. R.; Vassallo, A. M.; Chapman, A. C. Does battery storage lead to lower GHG emissions? *The*  
407 *Electricity Journal* **2017**, *30* (10), 1-7; DOI 10.1016/j.tej.2017.11.004.
- 408 (25) Craig, M. T.; Jaramillo, P.; Hodge, B. Carbon dioxide emissions effects of grid-scale electricity storage in a  
409 decarbonizing power system. *Environmental Research Letters* **2018**, *13*, 014004; DOI 10.1088/1748-  
410 9326/aa9a78.
- 411 (26) Arciniegas, L. M.; Hittinger, E. Tradeoffs between revenue and emissions in energy storage operation.  
412 *Energy* **2018**, *143*, 1-11; DOI 10.1016/j.energy.2017.10.123.
- 413 (27) Fisher, M. J.; Apt., J. Emissions and economics of behind-the-meter electricity storage. *Environmental*  
414 *Science & Technology* **2017**, *51* (3), 1094-1101; DOI 10.1021/acs.est.6b03536.
- 415 (28) Mago, P. J.; Luck, R. Potential reduction of carbon dioxide emissions from the use of electric energy storage  
416 on a power generation unit/organic Rankine cycle. *Energy Conversion and Management* **2017**, *133*, 67-75; DOI  
417 10.1016/j.enconman.2016.11.062.
- 418 (29) Summerbell, D. L.; Khripko, D.; Barlow, C.; Hesselbach, J. Cost and carbon reductions from industrial  
419 demand-side management: Study of potential savings at a cement plant. *Applied Energy* **2017**, *197*, 100-113;  
420 DOI 10.1016/j.apenergy.2017.03.083.
- 421 (30) Poullikkas A. A comparative assessment of net metering and feed in tariff schemes for residential PV

422 systems. *Sustainable Energy Technologies and Assessments* **2013**, 3, 1-8; DOI 10.1016/j.seta.2013.04.001.

423 (31) Sun C.; Lin B. Reforming residential electricity tariff in China: Block tariffs pricing approach. *Energy Policy*

424 **2013**, 60, 741-752; DOI 10.1016/j.enpol.2013.05.023.

425 (32) Fares, R. L.; Webber, M. E. The impacts of storing solar energy in the home to reduce reliance on the utility.

426 *Nature Energy* **2017**, 2, 17001; DOI 10.1038/nenergy.2017.1.

427 (33) McKenna, E.; McManus, M.; Cooper, S.; Thomson, M. Economic and environmental impact of lead-acid

428 batteries in grid-connected domestic PV systems. *Applied Energy* **2013**, 104, 239-249; DOI

429 10.1016/j.apenergy.2012.11.016.

430 (34) *Electric power sales, revenue, and energy efficiency*; Form EIA-861; U.S. Energy Information

431 Administration: Washington, DC, 2016: <https://www.eia.gov/electricity/data/eia861/>.

432 (35) *Electricity Marginal Factor Estimates*; Center For Climate and Energy Decision Making: Pittsburgh, PA

433 2017; <https://cedm.shinyapps.io/MarginalFactors/>.

434 (36) Siler-Evans, K.; Azevedo, I. L.; Morgan M. G. Marginal Emissions Factors for the U.S. Electricity System.

435 *Environmental Science & Technology* **2012**, 46 (9), 4742-4748; DOI 10.1021/es300145v.

436 (37) *Commercial and Residential Hourly Load Profiles for all TMY3 Locations in the United States*; Office of

437 Energy Efficiency & Renewable Energy: Washington, DC, 2013; [https://openei.org/doe-](https://openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states)

438 [opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states](https://openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states).

439 (38) *Building America House Simulation Protocols*; TP-550-49426; Energy Efficiency & Renewable Energy:

440 Washington, DC, 2010: <https://www.nrel.gov/docs/fy11osti/49246.pdf>.

441 (39) *National Renewable Energy Laboratory. National Solar Radiation Data Base*: National Renewable Energy

442 Laboratory: Golden, CO, 2015; [http://rredc.nrel.gov/solar/old\\_data/nsrdb/](http://rredc.nrel.gov/solar/old_data/nsrdb/)

443 (40) Jamaly, M.; Bosch, J. L.; Kleissl, J. Aggregate Ramp Rates of Distributed Photovoltaic Systems in San Diego

444 County. *IEEE Transactions on Sustainable Energy* **2012**, 4 (2), 519-526; DOI 10.1109/TSTE.2012.2201966.

445 (41) *Current Technical Support Document (2016): Technical Update to the Social Cost of Carbon for Regulatory*

446 *Impact Analysis under Executive Order 12866*; Interagency Working Group on Social Cost of Greenhouse Gases,

447 United States Government: Washington, DC, 2016; <https://www.epa.gov/sites/production/files/2016->  
448 [12/documents/sc\\_co2\\_tsd\\_august\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf).

449 (42) *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies*;  
450 Smart Grid Investment Grant Program; U.S. Department of Energy Electricity Delivery & Energy Reliability:  
451 Washington, DC, 2016;  
452 [https://www.energy.gov/sites/prod/files/2016/12/f34/CBS\\_Final\\_Program\\_Impact\\_Report\\_Draft\\_20161101\\_0.](https://www.energy.gov/sites/prod/files/2016/12/f34/CBS_Final_Program_Impact_Report_Draft_20161101_0.pdf)  
453 [pdf](https://www.energy.gov/sites/prod/files/2016/12/f34/CBS_Final_Program_Impact_Report_Draft_20161101_0.pdf).

454 (43) *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination*  
455 *of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic*  
456 *Rates, and Other Statutory Obligations*; Rulemaking 12-06-013; California Public Utilities Commission: Palo  
457 Sacramento, CA, 2015; <http://www.cpuc.ca.gov/>.

458 (44) *In the matter, on the Commission's own motion, to implement the provisions of Sections 173 and 183(1) of*  
459 *2016 PA 342*; Case Number U-18383; Michigan Public Service Commission: Lansing, MI, 2017;  
460 <https://www.michigan.gov/mpsc/>.

461 (45) *JEA Distributed Generation Policy*; Jacksonville Electric Authority: Jacksonville, FL, 2017:  
462 [https://www.jea.com/Environment/Net.../New\\_Distributed\\_Generation\\_Policy/](https://www.jea.com/Environment/Net.../New_Distributed_Generation_Policy/).

463 (46) *Commission Rulemaking Amendments to Net Energy Billing Rule Chapter 313*; Case Number 2016-00222;  
464 Maine Public Utilities Commission: Hallowell, ME, 2016; <https://www.maine.gov/mpuc/>.

465 (47) *Inquiry by the Department of Public Utilities on its own Motion into the eligibility of energy storage*  
466 *systems to net meter*; Order Number 17-146; Massachusetts Department of Public Utilities: Boston, MA, 2017;  
467 <https://www.mass.gov/orgs/departement-of-public-utilities>.

468 (48) *Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource*  
469 *Planning and Resource Acquisition*; Dockets UE-151069 and U-161024 (Consolidated); Washington Utilities  
470 and Transportation Commission: Olympia, WA, 2017; <https://www.utc.wa.gov>.



471 (49) *Decision regarding net energy metering interconnection eligibility for storage devices paired with net*  
472 *energy metering generation facilities*; Decision no. 14-05-033; California Public Utilities Commission:  
473 Sacramento, CA, 2014; <http://www.cpuc.ca.gov/>.

474 (50) *Application of San Diego Gas & Electric Company (U 902 E) For Approval of Distribution Resources*  
475 *Plan*; Application A.15-07-003; San Diego Gas & Electric Co: San Diego, CA, 2015:  
476 [https://www.sdge.com/regulatory-filing/23406/application-san-diego-gas-electric-company-u-902-e-approval-](https://www.sdge.com/regulatory-filing/23406/application-san-diego-gas-electric-company-u-902-e-approval-its-2018-energy)  
477 [its-2018-energy](https://www.sdge.com/regulatory-filing/23406/application-san-diego-gas-electric-company-u-902-e-approval-its-2018-energy).

478 (51) Babacan, O.; Ratnam, E. L.; Disfani, V. R.; Kleissl, J. Distributed energy storage system scheduling  
479 considering tariff structure, energy arbitrage and solar PV penetration. *Applied Energy* **2017**, *205*, 1384-1393;  
480 DOI 10.1016/j.apenergy.2017.08.025.

481 (52) Ratnam, E. L.; Weller., S. R.; Kellett, C. M. An optimization-based approach to scheduling residential battery  
482 storage with solar PV: assessing customer benefit. *Renewable Energy* **2015**, *75*, 123-134; DOI  
483 10.1016/j.renene.2014.09.008.

484 (53) Zhang, C.; Wei, Y.; Cao, P.; Lin, M. Energy storage system: Current studies on batteries and power condition  
485 system. *Renewable and Sustainable Energy Reviews* **2018**, *82* (3), 3091-3106; 10.1016/j.rser.2017.10.030.

486 (54) *In the matter of the application of Arizona Public Service Company for a hearing to determine the fair value*  
487 *of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon,*  
488 *to approve rate schedules designed to develop such return*; Docket no. E-01345A-16-0123; Arizona Corporation  
489 Commission: Phoenix, AZ, 2017; <https://www.azcc.gov/>.

490 (55) *Greenhouse Gas Equivalencies Calculator*; United States Environmental Protection Agency: Washington,  
491 DC, 2017; <https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator/>.

492 (56) *WattTime API for Automated Emissions Reduction*; WattTime: San Francisco, CA, 2018;  
493 <http://watttime.org/>.

494 (57) *Transformation of the Global Energy System*; REF 080118 - Case 00039936; World Economic Forum  
495 Global Future Council on Energy 2016-18: New York, NY, 2018;  
496 [http://www3.weforum.org/docs/White\\_Paper\\_Transformation\\_Global\\_Energy\\_System\\_report\\_2018.pdf](http://www3.weforum.org/docs/White_Paper_Transformation_Global_Energy_System_report_2018.pdf).