Addressing integration challenges of high shares of residential solar photovoltaics with battery storage and smart policy designs

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Abstract
In many countries, the integration of growing shares of residential solar photovoltaics is beginning to challenge existing electricity systems. First, residential solar photovoltaics aggravates sharp system-wide load changes and, in turn, increases the need for fast-ramping generation capacity. Second, it reduces the demand for electricity provision from the grid, causing an increase in electricity prices as grid costs are recovered over smaller volumes of electricity. Battery storage (BS) mitigates the first integration challenge by flattening the system-wide load, but elevates the second by increasing self-consumption behind-the-meter. In face of this dilemma, the integration of high shares of residential solar photovoltaics requires policymakers to re-design public support policies. In this article, we develop an agent-based model to simulate California’s residential ‘solar-plus-storage’ market between 2005 and 2030 in four different policy scenarios. By applying a multi-technology, multi-policy approach, we quantify the complex interplay between the diffusion of individual technologies, several interacting policies and systemic challenges. Our results show that California’s policy status quo initiated a BS uptake and, in turn, a flattening of the system, but, in the long run, will increase the electricity prices. To avoid this, we outline a policy reorientation—including a gradual phase-out of the prevailing feed-in remuneration and an introduction of fixed charges for owners of solar photovoltaic systems. Our results imply that the policy debate should be re-focused away from a single-technology single-policy perspective towards a system integration perspective. Neglecting this could not only jeopardize the affordability of electricity and climate change mitigation plans, but also put at risk the reliability of the electricity supply system. With investment costs of renewables expected to continue to decrease, this further implies that even countries without public support for renewables are likely to face challenges associated with their integration.

1. Introduction
In many countries, widely deploying variable decentralized renewable energy resources has become central to reducing CO2 emissions and mitigating climate change (REN21 2017). Driven by rapid technological learning and policy support, solar photovoltaics (PV), the most prominent renewable after wind, has begun to be taken up over the last decade (IEA 2014b). However, growing deployment of PV systems now challenges centralized electricity systems. Existing systems can only accommodate PV to a limited extent; studies estimate up to 25% of total energy in Japan (IEA 2014), 45% in Brazil (IEA 2014) and 50% in Germany (Kondziella and Bruckner 2016). Nevertheless, higher PV market shares aggravate sharp system-wide residual load increases at sunset, demanding more fast-ramping generation capacity (Agnew and Dargusch 2015). Particularly, residential PV—often small in scale, non-dispatchable, and spatially distributed—jeopardizes the reliability of electricity systems, which traditionally have been optimized for large-scale, centralized generation and long-distance transmission (Passy et al 2011). One solution to support high shares of residential PV is stationary battery storage (BS) that increases self-consumption behind-the-meter (Zahedi 2011, Braff et al 2016,
Creutzig et al (2017), enhances matching between a household’s demand and PV generation, and thus counters the diurnal cycle. If the expected cost reductions can be realized (Kittel et al 2017, Schmidt et al 2017), BS could diffuse market-wide, allowing more residential PV to be integrated without jeopardizing grid reliability. Yet, a widespread shift towards the combination of residential PV and BS—so-called ‘solar-plus-storage’—further reduces households’ demand for grid electricity. In the case of volumetric tariffs, this increases electricity prices as grid costs are recovered over smaller volumes (Laws et al 2017). Such a redistribution, combined with utilities’ feed-in remuneration (FIR) expenses, is likely to compromise the affordability of electricity—particularly for low-income households (Vaishnav et al 2017)—and may eventually erode public acceptance of renewable support policies.

Many countries are likely to experience these integration challenges (IEA 2017a); indeed, renewable energy front-runners already are. In March 2018, California’s system operator measured an average 7 GW capacity ramp between 5 pm and 8 pm—compared to 2 GW in 2012—accounting for one-fourth of the state’s daily peak demand (Pyper 2018b). This steep ramp urged California’s independent system operator to bring on a record amount of generation resources over a short time, calling for additional installations of fast-ramping capacity (e.g. gas peaker plants) that have the ability to start and stop multiple times per day (CAISO 2013). At the same time, net energy metering (NEM), the prevailing FIR for residential PV in California, will cost ratepayers $1.1 billion per year in 2020 (CPUC 2013). In Germany, due to a high feed-in tariff and industry exemptions, the renewable energy levy’s share of the total electricity price increased from approximately 10% in 2007 to 25% in 2014 (BDEW 2017). This led to public debate about the social acceptance of decentralized renewables that, ultimately, decelerated their annual diffusion (Hoppmann et al 2014a).

To support residential PV’s continued growth, public policymakers face the dilemma that addressing one integration challenge will ultimately exacerbate the other. For example, German policymakers have started to reduce the compensation for surplus PV electricity exported to the public grid (Hoppmann et al 2014a), and New York redesigned retail rates to counter the redistribution of grid costs (Pyper 2018a). While both measures hold down prices, they reduce households’ savings from PV and BS installations and, in turn, might decelerate the diffusion of the two technologies.

Previous research assesses the financial viability of standalone PV systems (Dargouth et al 2011, Comello and Reichelestein 2017), their historical and potential future diffusion (Palmer et al 2015, Dong et al 2017) and integration challenges (Passey et al 2011, Eid et al 2014, Picciariello et al 2015, Lazar 2016a, Barbose 2017, Johnson et al 2017, Kubli 2018). For solar-plus-storage systems, literature analyses the economic performance of BS at particular times (Hoppmann et al 2014b, Lehr et al 2017, Uddin et al 2017, Cerino Abdin and Noussan 2018), discusses adoption dynamics (Agnew et al 2018), and evaluates the long-term impact of solar-plus-storage on the power system (Klingler 2017, Yu 2018). However, literature thus far provides only little understanding of the diffusion of PV and BS across time in the face of the complex interplay between technologies, interacting public policies, and systemic challenges. To fill this gap, we develop an agent-based model to simulate the diffusion of PV and BS and their collective impact on climate change mitigation, the reliability of the electricity system, and the affordability of electricity. Applying such a multi-technology, multi-policy approach helps to illuminate the long-term dynamics between individual policy instruments, while considering systemic feedback loops and local agent interaction. Building on the case of residential solar-plus-storage in California, we examine the three most relevant policy instruments: upfront support, retail-rate design and FIR. We simulate the interaction between California’s households, electric utilities and the system operator between 2005 and 2030 in four different policy scenarios.

2. Methodology

2.1. Agent-based model

Our model aims to evaluate the impact of different combinations of policy instruments (scenario input) on the diffusion of PV and BS and their integration challenges (key output), as depicted in figure 1. We use an agent-based modeling approach as it is well suited to capture how the system behaviors—here the diffusion of PV and BS and their integration challenges—emerge from the local interaction of a population of autonomous and heterogeneous households (Bale et al 2015, Haelg et al 2018). The scenario input to the model comprises the three most relevant policy instruments that economically affect California’s residential solar-plus-storage market (Dargouth et al 2011, McLaren et al 2015, Barbose et al 2016, Ossenbrink et al 2018); upfront support subsidies (PI 1) lower the investment costs; retail-rate designs (PI 2) determine the composition of residential electricity bills; FIR (PI 3) sets compensation for surplus PV generation exported to the grid. The agent-based model covers the 58 Californian counties and depicts the roughly 12 million residential households (resized by a factor of 1:10,000), three investor-owned electric utilities (IOUs) (serving >80% of California’s electricity customers), and California’s Independent System Operator (CAISO). Its four key outputs are: (I) the annual diffusion of residential PV and BS; (II) CO₂ emissions avoided (climate change mitigation); (III) the hourly need for fast-ramping (reliability of the
electricity system); and (IV) the increase in retail electricity prices caused by the diffusion of PV and BS (affordability of electricity). The model runs from 2005 to 2030, each year executing the three modules described below; the years 2005–17 serve to calibrate the model based on historical deployment and policies. A full model description including detailed input data and sensitivity analysis is provided in the supplementary material.

In the first module, the system operator forecasts hourly wholesale electricity prices for the upcoming year, based on the result of an ex-ante statistical regression analysis. In this, we have regressed the hourly wholesale market prices as a dependent variable on the hourly system-wide electricity demand, the hourly share of thermal and solar generation in the electricity mix, annual prices for gas and coal and dummy variables to account for unobserved annual effects, using historical data between 2010 and 2015. We then implemented the regression weights as input parameters in the model, assuming that the independent variables have a constant and linear effect between 2005 and 2030. While all other independent variables are included as exogenous in its forecast, the system operator calculates the hourly system-wide electricity demand through totalizing the demand of residential households—therby considering households’ demand changes due to previous PV and BS adoption (see, module 3)—and complementing with an exogenous commercial and industrial demand.

In the second module, utilities set the hourly retail electricity prices for the upcoming year, in the context of the general rate case. The general rate case is an official procedure utilities go through over every three years. However, in our model, utilities go through it every year as a simplification. To do so, they first calculate their revenue requirement for the upcoming year, i.e. costs for providing electricity to residential customers plus a fixed margin. Utility costs arise due to utility-owned generation, distribution and transmission infrastructure, renewable energy procurement, wholesale electricity market purchases, and FIR (see, module 1). We here assume that previous PV and BS adoption does not affect costs for utility-owned generation, and the distribution and transmission infrastructure, but reduces the amount of renewable energy procurement. We further assume that utilities, instead of buying surplus PV electricity from households, could do so at the wholesale market. The price difference between the FIR and electricity purchased at the wholesale market, therefore, results in additional costs or savings for utilities. Utilities then allocate the revenue requirement—corrected for revenues generated through fixed and demand charges—across their residential customers (considering their forecasted demand), taking into account the design of the current retail rate. For example, in case of a flat volumetric charge, utilities divide the corrected revenue requirement by the residential demand.

In the third module, households may adopt residential PV and BS systems, based on a three-step decision-making process. First, households may develop a project idea to adopt a technology, resulting from an assessment of their personal awareness, peer effects and the availability of general information available on both technologies—all been found to be important indicators of technology adoption in previous literature (Faiers and Neame 2006, Faiers et al 2007, Yuan et al 2011, Zhai and Williams 2012, Rai and Robinson 2013, Palmer et al 2015, Reeves et al 2017). Second, households that developed a project idea assess and compare the investment opportunities (standalone PV, solar-plus-storage systems, and BS retrofits), using a net present calculation, which covers upfront investment cost, maintenance cost, and
annual electricity bill savings; retail electricity price (see, module 2) and policy instruments (see, scenario input) strongly affect the results of the net present value calculation. For this calculation, households also consider various technology specifications; for example, battery degradation is indirectly accounted for by a 20% minimum state of charge (for details see supplementary material). Third, the households duly adopt the best-performing option if the net present value is positive. Particularly ‘green’ households (i.e. strong personal awareness), however might adopt the technology despite unfavorable economics.

By endogenising the mechanisms behind the system operator’s price setting, utilities’ rate-making, and households’ technology adoption our model closes the feedback loop between PV and BS adoption and the retail electricity price, a key driver of both technologies’ profitability and thus diffusion.

2.2. Policy scenarios
From the current policy debate in California, we derive four policy scenarios, S1–S4 are available online at stacks.iop.org/ERL/14/074002/mmedia (see table 1). In the ‘Current Path’ scenario (reference, S1), we evaluate the policy status quo in 2018, including 2017’s controversial change of prevailing FIR from NEM 1.0 to 2.0. Under NEM 2.0, households that install a PV system are credited for surplus electricity on the retail-price level (minus a non-bypassable charge (NBC) for any electricity purchased from the grid) and will automatically be switched to a time-of-use (TOU) dependent rate design. S1 also includes announced but not yet effective policy changes, such as the planned phase-out of upfront support, comprising investment tax credits (ITCs) and the Self-Generation Incentive Program (SGIP) in 2022. In the ‘2016 Policy Freeze’ scenario (S2), we extrapolate the prevailing policy landscape of 2016 until 2030. This allows us to estimate developments if policies had not changed, and analyze the impact of the 2017 FIR and rate-design adjustments in isolation. S2 thus includes strong upfront support (ITC, SGIP) until 2030, tiered instead of TOU based volumetric charges, and a strong FIR (NEM 1.0 instead of NEM 2.0). We also study the ‘2018 Policy off’ scenario (S3), which depicts the immediate shutdown of upfront support (ITC, SGIP) and FIR (NEM 2.0) in 2018. This reflects the debate about the need for support policies, as prices are already low for PV panels, and falling rapidly for battery packs.

However, S1–S3 do not include measures to address the retail electricity price increase driven by utilities’ FIR expenses and redistribution of grid cost. Several options have been proposed to deal with the latter, including demand charges and fixed charges (Hledík 2014, Borenstein 2016). While demand charges are common in commercial and industrial settings, fixed charges—although common in other countries (e.g. UK) (Rhys 2018)—are emerging as a new theme for retail rate design in the Californian context (Pyper 2018a). Therefore, we developed an ‘Alternative Path’ scenario (S4) that aims to stabilize retail prices by combining a gradual phase-in of a monthly $35 fixed charge for PV customers from 2022 and a phase-out of the prevailing FIR (NEM 2.0) from 2019, both transitions spanning nine years. Phasing out a FIR over several years is similar to the case of Germany, where policymakers set fixed annual reductions of feed-in tariffs in foresight of renewables’ price reduction (Bundesgerichtshof 2000, Frondel et al. 2010).

Gray boxes indicate changes of policy instrument compared to the reference scenario S1; Description of the historical combinations of policy instruments: (PI 1) A federal 30% ITC for residential and commercial solar-energy systems has been introduced in 2005, and will be phased out in 2022. The ‘California Solar Initiative’ (CSI) was introduced in 2007 and already achieved its targets in 2016. Upfront support subsidies for BS include the SGIP since 2009. On top of this, BS are eligible for federal ITCs@30% since 2013. Both instruments will be phased out in 2022. (PI 2) Since 2001, the retail electricity rate has been designed as a five-block, tiered rising rate structure. In 2015, a tier consolidation process began, by moving all residential customers first to three blocks by 2017, and subsequently to TOU rates in 2019 (Assembly Bill 327). (PI 3) Since 1996, residential PV customers are credited for surplus generated electricity within the NEM 1.0 scheme. As California’s IOUs reached a 5% capacity cap, they have begun to operate under NEM 2.0. This includes a one-time PV system interconnection fee, NBCs on each kWh of surplus electricity households feed into the grid and a mandatory switch to TOU rates for PV adopters only.

3. Results
3.1. Residential PV and BS diffusion
Following the ‘Current Path’ (S1) results in an ongoing diffusion of residential PV, peaking in 2020, and a strong uptake of BS, temporarily crashing in 2022 (see figure 2). For residential PV, the introduction of NBCs and the interconnection fee under NEM 2.0 causes a market fall in 2017. Although the residential PV market temporarily recovers, in 2021, the residential PV market stagnates, since the characteristics of late adopters (i.e. low electricity consumption, low income, small rooftop and low solar radiation) render investments in PV less attractive. By 2030, more than one-quarter of all households in California have installed a PV system, resulting in 14.1GW_p of residential PV capacity. BS adoption is triggered in 2017 by a combination of NBCs and TOU rates, as this
makes it profitable to store surplus electricity in off-peak hours and self-consume it in peak hours. In 2022, the BS market collapses due to the phase-out of upfront support, but recovers due to a global decline in battery pack prices. By 2030, every second PV owner in California has also installed a BS system, resulting in 12.1 GWh of storage capacity.

Under the ‘2016 Policy Freeze’ scenario (S2, see figure 2), PV diffusion would have avoided the temporary drop seen in S1 and, instead, peaked as early as 2018, while BS deployment would have remained low until 2030. Cumulative installed capacity by 2030 would have been similar to S1, despite continuous strong upfront support. BS diffusion would have followed the historical trend, showing no market uptake (i.e. <1% adoption rate by 2030) despite significant upfront support. This is due to NEM 1.0, which credits surplus electricity at retail levels. Thus, NEM 1.0 effectively positions the electricity grid as a free-of-charge, unlimited and 100% efficient virtual energy storage system.

In the ‘2018 Policy Off’ scenario (S3), the 2018 shutdown of FIR and upfront support triggers an immediate collapse of the residential PV market, but a gradual uptake of BS (see figure 2). Although the residential PV market plummets from an annual level of roughly 1370 MWp in 2016 to 50 MWp in 2018, it fully recovers within five years, driven by a fall in global PV panel prices and the uptake of BS. The higher self-consumption rate of solar-plus-storage systems in the absence of a FIR and decreasing battery-pack prices renders such systems more profitable than standalone PV.

In the ‘Alternative Path’ scenario (S4), the phased adjustments of FIR and rates result in an ongoing PV diffusion and, in contrast to S1, mitigates the BS market crash (see figure 2). Interestingly, a PV crash is also averted, despite the negative impact of both policy adjustments on the profitability of PV investments. The stepwise reduction of bill savings from PV installations corresponds with falling installation costs (due to installation firms’ local learning) and PV panel prices (due to global technology learning). We see faster BS uptake than in S1, driven by a stronger incentive for self-consumption (NEM 2.0 phase-out). Yet, in the late 2020s, only a few non-adopters still suit BS investments, resulting in earlier inflection in the rate of adoption. By 2030, the diffusion level is similar to S1 at 15%–20% adoption of BS.

### 3.2. CO₂ emissions and integration challenges

In the ‘Current Path’ (S1), continuing with strong FIR and upfront support leads to high CO₂ emission savings and mitigates the need for fast-ramping capacity, but retail prices surge (see figure 3). Extensive adoption of residential PV displaces conventional power generation at midday and results in a steady increase of avoided CO₂ emissions—cumulatively, 127 Mt by 2030. However, with increasing PV market share, fast-ramping capacity (i.e. flexible resources

| Name | P1: Upfront support | P12: Retail electricity rate design | P13: Feed-in remuneration |
|------|---------------------|------------------------------------|---------------------------|
| H    | Historical (2005–2017) | Tiered (three blocks) since 2016; before tiered (five blocks); time-of-use (TOU) for PV customers in mid-2017 (included in NEM 2.0) | $0 | NEM 1.0 since 1996; |
| S1   | Current path (Reference) | Phase-out of ITC and SGIP until 2022 | Introduction of TOU for all electricity customers in 2019 (AB327) | $0 | NEM 2.0 |
| S2   | 2016 Policy Freeze | Upfront support at 2016 level | Tiered (three blocks) | $0 | NEM 1.0 |
| S3   | 2018 Policy Off | Immediate shutdown of ITC and SGIP in 2018 | Switch to flat volumetric charges in 2018 | $0 | Immediate shutdown of NEM 2.0 in 2018 |
| S4   | Alternative path | Phase-out of ITC and SGIP until 2022 | Introduction of TOU for all electricity customers in 2019 (AB327) | $35/month for solar PV owners; Phase-in 2022–30 | Phase-out of NEM 2.0 2019–27 |
such as gas peaker plants that can be quickly adjusted to meet sharp changes in electricity demand) is needed after sunset when PV electricity production declines. At market introduction, PV typically served peak demand at midday. Yet, already in 2017, system load was peaking in evening hours, necessitating 3.4 GW generation capacity being ramped up between 1 pm and 7 pm. While continuous adoption of standalone PV until 2030 would have exacerbated this, the uptake of BS holds it at bay, maintaining the need for fast-ramping capacity on an average day in 2030 at 5 GW. However, the uptake of solar-plus-storage systems comes at a cost: under the purely volumetric retail-rate design in S1, BS adoption exacerbates the redistribution of grid costs. Despite the introduction of two specific measures (NBCs and interconnection fee) to decelerate such redistribution, by 2030 the retail electricity price shoots up by 5.6¢/kWh.

Extrapolating the 2016 policy landscape (S2) would have resulted in CO₂ emission reductions and price increases on S1 levels, but burdened the future system with a huge demand for fast-ramping capacity (see figure 3). This is depicted by the system load in S2, including a ‘belly’ around midday and a ‘neck’ in the evening. By 2030, the duck’s neck reflects a ramp-up capacity demand of 8.2 GW, equivalent to 28 peaker plants (~300 MW each). Since we only analyze the average day, such demand is expected to increase by a factor of 2–3 (Pyper 2018b) on sunny spring days with low cooling demand and strong solar irradiation at midday. The increase in retail electricity price is similar to S1, although no specific political action is taken to address the redistribution of grid costs, demonstrating the limited impact of NEM 2.0 on this integration challenge. In contrast to S1, the main
driver of price increases in S2 is the comprehensive FIR (rather than BS uptake).

In the ‘2018 Policy Off’ scenario (S3), the total withdrawal of support for PV and BS maintains the need for fast-ramping capacity at S1 level and reduces the increase in electricity price, but decelerates CO$_2$ emission reductions, amounting to only 98 Mt by 2030 (see figure 3). Such a slowdown could jeopardize the contribution of solar-plus-storage owners to California’s CO$_2$ emission reduction targets. The retail electricity price shows an initial drop in 2018, induced by the FIR shutdown and fewer PV owners bypassing grid costs. However, due to the uptake of BS and the recovery of the PV market, the retail price rockets by 4.1¢/kWh by 2030—despite the absence of policy support for PV or BS.

In contrast to S1–S3, the ‘Alternative Path’ (S4) cuts the retail electricity price increase in half, while
still ensuring high CO₂ emission reductions and a manageable need for fast-ramping capacity (both at S1 levels). The electricity price increase remains stable, starting in 2022, despite an ongoing diffusion of PV and BS. This is achieved by the combination of a phase-out of FIR and a phase-in of fixed charges for PV adopters, thus ensuring that all customers pay for their grid connection. By 2030, the electricity price increase is just 2.9¢/kWh.

4. Discussion and conclusion

Simulating California’s residential market for solar PV and BS, we find that ongoing policy reorientation is crucial to the further diffusion and system integration of both technologies. Although controversially discussed, we can show that the adjustment of California’s NEM scheme in 2017 has been a first step towards addressing the emerging integration challenges of PV. The switch towards TOU rates and the introduction of NBCs initiated a BS uptake and, in turn, a flattening of the system load. Yet, if the policy status quo were preserved until 2030, high PV and BS shares would increase the electricity price to twice the average US household’s willingness to pay for renewable energy (Sundt and Rehdanz 2015). As an immediate shutdown of policy support would initially decelerate such a price increase, but cause a PV market crash, the need for a subtler policy is evident. One possibility is outlined in the ‘Alternative Path’. Our results show that the phase-out of NEM, combined with the introduction of fixed charges for PV customers only, counters the electricity price increase and ensures a manageable need for fast-ramping capacity, at the ‘cost’ of slightly lower carbon emission reductions. Yet, the adverse effect that a NEM phase-out and fixed charges can have on self-generation means policymakers must implement both measures with care. Our results indicate that only implementing both measures over several years—thereby aligning the reduction in support policies with the reduction in technology costs—prevents a significant market reduction of PV and BS. Further, the fixed charges are effective for PV owners alone; thus alleviating the negative impact such charges can have on the electricity bill of non-adopting low-income households (McLaren et al 2015). Although regulators have often declined utilities’ requests to implement fixed charges, they emerge as a common theme in retail-rate designs (Pyper 2018a). Also, from an economics perspective, a fixed charge is the ‘least bad’ way for utilities to recover fixed costs (Borenstein 2016). That being said, we do recommend the ‘Alternative Path’ to ensure grid reliability and public acceptance of renewable energy policies—despite slightly lower CO₂ emission reductions. However, this obviously depends on how policymakers weigh the competing policy objectives—if reducing carbon emissions is their prime goal, California’s policymaker might not be willing to either end the success story of NEM nor implement a heavy fixed charge.

Beyond California, countries that lead in renewable energy increasingly face the challenge of how and when to phase out renewables support. If support stays high relative to the underlying cost of the technology, they risk generating windfall profits, increasing electricity prices and even jeopardizing the affordability of electricity. In contrast, if support is cut off, they risk decelerating technology diffusion, causing boom-and-bust cycles with negative consequences for industry and consumers alike (Del Rio and Mir-Artigues 2012), and jeopardizing the contribution of renewables to climate change mitigation. However, the timing and approach of phasing-out support policies hinge on both the regional context and the availability of complementary technologies (Markard and Hoffmann 2016). In regards to the regional context: depending on the regional electricity mix, the installation of additional renewables might displace coal or even lignite fueled power plants (Schivley et al 2018), and thus creating additional benefits, for example, reducing air-pollution and water usage (Deng et al 2017). In contrast, in other regions, additional PV installations may instead begin to displace low-carbon resources such as biomass or hydro. Further, depending on the capacity of the regional distribution grid, decentralized renewables cause grid congestions, requiring grid extensions (Passey et al 2011); and depending on the regional PV industry, the cost difference between PV and grid electricity can vary (Lang et al 2015)—despite a global PV panel market. In regards to complementary technologies: their availability, for example BS, allow owners of renewables to increase the value of on-site generated electricity and, in turn, may facilitate an earlier phase-out of support policies. We further show that certain support policies reduce the economic viability of complementary technologies and even impede their diffusion, whereas others only affect the targeted technology. Such unintended side effects should be considered in the discussion of when to phase out which support policies.

Even countries without public support for renewables are likely to face challenges associated with their integration. As their investment costs fall, renewables will continue to replace fossil fuels on a global scale. Moreover, some countries have begun to make on-site renewable electricity production mandatory for new buildings (EnDK 2015, Pyper 2018c). Facing such irreversible momentum (Obama 2017), policymakers may need to consider the potential losers from a transition towards a decentralized electricity system. Utilities face eroding electricity sales due to an ongoing shift to self-generation on a residential, neighborhood or community level (Castaneda et al 2017). While they have slowly started to change their business portfolios (Frei et al 2018), they may increase prices to cover fixed costs in the short term, thereby reinforcing the shift
towards prosumerism. Our results confirm such a ‘death spiral’ (Laws et al 2017), in that utilities’ electricity sales decline further, and the burden of financing the entire grid infrastructure is borne by fewer households. Considering that it is high-income households that typically invest in renewables (CPUC 2013, Vaishnav et al 2017), this burden might fall mainly on low-income households, thereby exacerbating fuel poverty of already socially disadvantaged groups.

By applying a multi-technology, multi-policy approach, we can quantify the complex interplay between the diffusion of individual technologies, several interacting policies and systemic challenges. Further, endogenising the mechanisms behind technology adoption of households, rate-making by utilities and price-setting in wholesale markets allows us to evaluate the repercussions of systemic feedback loops, including the reciprocal influence of technology adoption and electricity prices. Such a holistic analysis, however, requires some simplifying assumptions of which we highlight two in the following. First, while literature provides a comprehensive list of the value of solar PV—for example, reducing climate impact (Hansen et al 2013, Lazar 2016b)—we focus only on the changes in the variable costs for utilities and their redistribution. Yet, our analysis does not overlook solar PVs environmental benefits as we highlight carbon reduction as a key policy objective and, further, reflect on the societal willingness to pay a higher price for renewables. Second, we simplify the role that utility-scale PV and BS play for the electricity system. In our model, we consider utility-scale PV only indirectly through an evolving electricity mix—for example, solar PV increases its share from <1% in 2005 to ~30% in 2030—which, in turn, affects the net load and wholesale electricity prices. Similarly, our model does not reflect utility-scale BS, which has already proven to provide important grid services, but might be less valuable compared to residential storage as it is located away from the point of consumption (Fitzgerald et al 2015). Additional limitations of our model relate to its focus on stationary BS, behind-the-meter applications, and support policies for voluntary technology adoption. For future work, we thus call for an analysis that is more detailed on the value of solar and combines policy analyses for residential and utility-level PV and BS. Future work should also include a broader range of support policies, particularly regulatory instruments like mandatory on-site renewable electricity production for new buildings (Pyper 2018c). Moreover, it seems to be a promising avenue for future studies to include additional applications of stationary BS such as peak-shaving and, importantly, to consider mobile batteries of electric vehicles (Wolinetz et al 2018) due to their immense charging loads and storage capacity (Sovacool et al 2017, Wolinetz et al 2018).

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