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7 **Net Metering and Market Feedback Loops:**
8 **Exploring the Impact of Retail Rate Design on Distributed**
9 **PV Deployment**
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Abstract

The substantial increase in deployment of customer-sited solar photovoltaics (PV) in the United States has been driven by a combination of steeply declining costs, financing innovations, and supportive policies. Among those supportive policies is net metering, which in most states effectively allows customers to receive compensation for distributed PV generation at the full retail electricity price. The current design of retail electricity rates and the presence of net metering have elicited concerns that the possible under-recovery of fixed utility costs from PV system owners may lead to a feedback loop of increasing retail prices that accelerate PV adoption and further rate increases. However, a separate and opposing feedback loop could offset this effect: increased PV deployment may lead to a shift in the timing of peak-period electricity prices that could reduce the bill savings received under net metering where time-varying retail electricity rates are used, thereby dampening further PV adoption. In this paper, we examine the impacts of these two competing feedback dynamics on U.S. distributed PV deployment through 2050 for both residential and commercial customers, across states. Our results indicate that, at the aggregate national level, the two feedback effects nearly offset one another and therefore produce a modest net effect, although their magnitude and direction vary by customer segment and by state. We also model aggregate PV deployment trends under various rate designs and net-metering rules, accounting for feedback dynamics. Our results demonstrate that future adoption of distributed PV is highly sensitive to retail rate structures. Whereas flat, time-invariant rates with net metering lead to higher aggregate national deployment levels than the current mix of rate structures (+5% in 2050), rate structures with higher monthly fixed customer charges or PV compensation at levels lower than the full retail rate can dramatically erode aggregate customer adoption of PV (from -14% to -61%, depending on the design). Moving towards time-varying rates, on the other hand, accelerates near- and medium-term deployment (through 2030) but slows adoption in the longer term (-22% in 2050).

Keywords: solar; photovoltaics; net metering; feedback; electricity rate; rate design

1 Introduction

Deployment of distributed solar photovoltaics (PV) has expanded rapidly in the United States, fueled by steeply declining costs, financing innovations, and supportive public policies. Key among the supportive policies has been net metering, which typically compensates each unit of PV generation at the customer's prevailing retail electricity rate. The rapid growth of net-metered PV has provoked concerns that this practice allows PV customers to avoid paying their full share of fixed utility infrastructure costs, thus requiring the utility to raise retail prices for all customers (Brown and Lund 2013, Borlick and Wood 2014, Eid et al. 2014). Compounding that concern is the possibility of positive feedback between PV deployment and electricity rates, with PV-driven rate increases making net-metered PV even more attractive and thus accelerating further PV deployment and rate hikes (Cai et al. 2013, Costello and Hemphill 2014, Graffy and Kihm 2014). One proposed solution is to change electricity rate designs (Bird et al. 2013, Jenkins and Perez-Arriaga 2014, McConnell et al. 2015). Frequently such proposals entail reallocating a portion of cost recovery from per-kilowatt-hour volumetric charges to fixed customer charges and/or per-kilowatt demand charges (Faruqui and Hledik 2015, NC Clean Energy Technology Center 2015), while other proposals involve reconsidering net metering rules.

Table 1. Feedback mechanisms between PV adoption and retail electricity prices addressed in this paper

Rate Feedback Effect	Description	Affected Rates
Fixed Cost Recovery Feedback	Increases in average retail rates required to ensure fixed-cost recovery	Flat and Time-varying
Time-varying Rate Feedback	Changes in the timing of peak and off-peak periods under time-varying rate structures	Only Time-varying

This article, which is based upon a more expansive analysis presented in Darghouth et al. (2015), fills key gaps in the literature by examining the impacts of the two competing feedback dynamics on U.S. distributed PV deployment through 2050 for residential and commercial customers. We show whether and under what conditions retail rate changes caused by distributed PV might affect future PV deployment. We also show the impact on PV deployment of changes to retail rate design and net-metering rules. The results are meant to inform regulators and other decision makers as they consider potential changes to retail electricity rates that could affect PV's role in advancing policy objectives and customer choice. We present both national results as well as disaggregated results by customer segment or by state. The aggregated national results show the overall PV deployment patterns that are relevant to the PV market and industry more generally, whereas the distributions show the ranges in PV deployment results for states or customer segments, which could have implications for particular utilities or states who are interested in these more local possible feedback magnitudes or deployment levels.

1.1 Literature Review

The literature on this topic contains important gaps. Prior studies of the feedback between PV deployment and electricity rates have generally remained conceptual and hypothetical, with the notable exceptions of Cai et al. (2013), Chew et al. (2012), and Costello and Hemphill (2014). Furthermore, analyses of retail rate feedback effects have focused only on the possible *positive* feedback associated with under-recovery of fixed costs. A separate – and potentially offsetting – feedback may occur when increasing PV penetration shifts the temporal profile of wholesale electricity prices, potentially reduces bill savings for net-metered PV customers on time-varying rates, and thus discourages further PV adoption (Table 1). Numerous studies have demonstrated that the capacity value and wholesale market value of PV erode as penetrations increase (Mills and Wiser 2013, Hirth 2013, Gilmore et al. 2015), and Darghouth et al. (2014) explored the implications of this effect for time-based retail rates and the customer economics of PV systems. No studies to our knowledge, however, have estimated the impact of this effect on the *deployment* of distributed PV or contrasted it with the fixed-cost feedback mechanism. Key gaps also exist with respect to the effect of rate-design changes on PV deployment. Studies have focused on the impacts of retail rate structure on PV customer economics (Mills et al. 2008, Darghouth et al. 2011, Ong et al. 2010, Ong et al. 2012) but generally have not translated those findings into deployment effects.

This paper contributes to the larger discussion relating the impact of rate design and net metering to the revenue and profitability impacts of distributed solar on electric utilities, though we do not quantify this impact directly. A number of previous studies have identified the potential misalignments between net metering and utility cost structures (Cai et al. 2013, Duthu et al. 2014, Graffy and Kim 2014), and Satchwell et al. (2015) have modeled the potential impact of higher PV penetration on revenue and profitability metrics for two prototypical US electricity utilities. For two different utility business models – one vertically integrated utility and one wires-only utility – the authors found that as distributed PV levels increased, utility

revenues declined faster than costs. The study also found that the decrease in return on investment was greater for the wires-only utility than for the vertically integrated one, as was the increase in average retail rates (though the magnitudes were modest and nearly equivalent on a percentage basis between the two utilities), but that these impacts could be mitigated by a number of policy measures. Though linkages with this paper can be made, the revenue and utility profitability impacts of distributed PV are not the focus of this paper, and could be the subject of future research.

2 Data and Methods

We build on prior applications of the National Renewable Energy Laboratory (NREL) Solar Deployment System (SolarDS) model (e.g., Drury et al. 2013) by incorporating the two key feedback mechanisms between PV adoption and retail electricity prices (Table 1). This section describes the SolarDS model, data sources, and assumptions as well as our analysis scenarios and our methods for modeling electricity rate feedbacks. We do not explore customer defection from the grid owing to combined PV/storage solutions, which may decline in price over the study period (Bronski et al. 2014), because SolarDS is not equipped to evaluate storage solutions or defection decisions.

2.1 SolarDS model, data sources, and assumptions

The SolarDS model simulates the customer adoption of distributed PV using a bottom-up approach (where customer-adoption decisions depend on an economic comparison between PV system cost and the customer's electricity bill savings) with data from 216 solar resource regions and more than 2,000 electric utilities. It is an economic model and hence assumes that deployment is driven by economic considerations. The model was written in Microsoft Excel, using the Visual Basic for Applications programming language. The model is not currently publically available, though details about the input assumptions for and methodologies used in SolarDS are documented in Denholm et al. (2009), and the model structure is summarized in Figure 1. Each of these steps is summarized in the paragraphs below.

Figure 1. SolarDS model schematic (from Denholm et al. 2009)

The model has two central elements:

- 1) Customer economics of PV.** SolarDS calculates PV system lifetime cash flows based on simulated PV output from NREL's PVWatts model (Dobos 2014) for 216 solar resource regions (step 1 in Figure 1), utility-specific average revenue per kilowatt-hour (a proxy for retail rates) from U.S. Energy Information Administration (EIA) Form 861 (step 2), and

assumptions about PV system costs, performance-degradation rates, and state and federal incentives (step 3).

For input parameters, we assumed the installed prices for PV systems follow a trajectory that draws from the SunShot PV price target (a 75% price decline from 2010 levels by 2020) (U.S. Department of Energy 2012): residential PV system prices fall to \$1.60/W and commercial prices to \$1.34/W in 2020 (in 2013 U.S. dollars per peak watt-direct current), assuming an exponential decline in prices through 2020.

PV compensation under net metering with flat, volumetric retail rates (as are common for U.S. residential customers) is determined by the average electricity rate distribution in each state (differentiated by commercial and residential customers). For time-varying retail rates (e.g., time-of-use and real-time pricing), we used the System Advisor Model (Blair et al. 2014) to calculate PV-induced bill savings with and without time-varying rates, using 2013 rates available to residential customers in each state's largest utility. The ratio of bill savings with time-varying rates to that with flat rates as calculated through this approach was then used to estimate the customer's bill savings from PV under time-varying rates for other utilities in the state, for both residential and commercial customers. Our demand-charge methodology for commercial customers was not changed from the original SolarDS model; for demand charges that apply to commercial customers, SolarDS assumes that PV can displace 20%–60% of demand charges, depending on the building type, insolation, and season, as calculated using the EnergyPlus model for the original SolarDS. Rate escalation assumptions are from EIA's *Annual Energy Outlook* (EIA 2014a), extrapolated to 2050.

Average utility-specific rates, solar renewable energy credit (SREC) prices, and available state and utility incentives were updated to 2013 levels. State and utility incentives were updated as per the Database of State Incentives for Renewable Energy (DSIRE) database (NCSU 2014). All state incentives and SREC prices are assumed to ramp down linearly to reach zero in 2030, except for incentives that identify an earlier end date. The federal investment tax credit (ITC) was set to 30% for residential and commercial systems in 2014, and it is assumed to revert to zero for residential customers and to 10% for commercial customers at year-end 2016. We assume 70% of residential systems installed are third-party owned and hence benefit from the commercial ITC.

2) Customer adoption. Customer adoption depends on a comparison of electricity bill savings and the cost of the PV system (the “cash flow”). Using the PV system's lifetime cash flow, SolarDS adoption decisions are based on time-to-net-positive cash flow (i.e., payback period) for residential customers and internal rate of return for commercial customers.¹ SolarDS uses highly non-linear customer-adoption curves linking payback and rate of return to adoption rates as a percent of maximum market size adoption curves are available in Denholm et al. (2009). Maximum market size is based on the number of solar-appropriate

¹ We assume customers do not foresee the changing rates due to PV penetration levels and expect net metering to continue over the lifetime of their system. Additionally, PV customers are assumed to replace their systems at the end of their economic life, such that cumulative deployment cannot shrink.

households for the residential sector and the available solar-appropriate roof space for commercial customers (see Denholm et al. (2009) for details related to residential and commercial building stock assumptions). These market adoption curves, originally based on empirical data, incorporate some of the non-economic decision making regarding the purchase of PV systems (i.e. some customers choose not to adopt PV even at very low payback times). Using the market adoption curves and calculated maximum market sizes, the total PV adoption in each time period in each subregion is calculated (step 4 in Figure 1).

The size distribution of PV systems in the residential sector is based on the distribution of existing PV installations (Barbose et al. 2014).² For the commercial sector, PV system size is determined using roof size limitations and load assumptions from Denholm et al. (2009). In each geographical area considered, we aggregated adoption from each customer segment under each rate type and then summed up all installations to the state and national level (step 5 in Figure 1).

2.2 Retail rate design and PV compensation scenarios

Eight rate design and PV compensation scenarios are modeled in this analysis, including a reference scenario that provides a baseline (Table 2). This set of scenarios is by no means exhaustive, but rather consists of a representative and tractable number of the broader universe of potential rate design options. All scenarios include residential and commercial customer segments and project deployment of customer-sited PV through 2050.

For the reference scenario, we assumed a continuation of the current mix of rate designs and determined the proportion of customers facing flat rates, time-varying rates, and – for commercial customers – demand-charge rates using data from EIA Form 861 and previous SolarDS assumptions (Denholm et al. 2009). We assumed full net metering for the reference scenario, where all customer PV generation is effectively compensated at the retail rate.

² We recognize that the distribution of PV system sizes may change with time. Lower prices provide some customers incentive to install larger systems, while some rate design choices, such as partial net metering, would encourage smaller systems.

214 **Table 2. Rate design and PV compensation scenario assumptions**

Scenario	Customer retail rate assumptions	PV compensation assumptions
Reference	Reference mix of flat rates, time-varying rates, and demand charges from EIA Form 861 data	Net metering
\$10 fixed charge	Reference mix, but with residential rates adjusted with \$10 monthly charge	Net metering
\$50 fixed charge	Reference mix, but with residential rates adjusted with \$50 monthly charge	Net metering
Flat rate	All residential and commercial customers on flat rates	Net metering
Time-varying rate	All residential and commercial customers on time-varying rates	Net metering
Partial net metering	Reference mix	PV generation that displaces instantaneous load compensated at retail rates; PV generation exported to the grid (i.e. net-production) compensated at avoided-cost rate

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216 For the scenarios with monthly fixed customer charges, residential PV generation reduces the
217 customer's monthly bills by displacing the volumetric portion of the retail rate, but PV
218 generation does not affect the fixed charge. The variable portion of the rate is then calculated
219 for each utility, such that the combination of the variable portion and fixed customer charge is
220 equal to the utility-reported total revenue data from EIA Form 861. For the flat rate and time-
221 varying rate scenarios, all customers are assumed to be on either the flat rate or the time-
222 varying rate, respectively; these scenarios are designed to bound the potential rate mix options.
223 For partial net metering, customers are allowed to consume their PV generation directly, but
224 their net-production is compensated at a lower, avoided cost rate. This compensation
225 mechanism is similar to a feed-in tariff that is lower than the retail rate, as is currently the case
226 in Germany. Residential and commercial PV customers are assumed to self-consume 50% and
227 70% of total PV generation, respectively (E3 and CPUC 2013). The avoided cost rate depends on
228 regional PV penetration and natural gas prices. Detailed methods for determining PV energy
229 and capacity value can be found in the next section.

2.3 Modeling rate feedbacks

The original SolarDS model assumes retail rate structure and prices are independent of regional PV deployment and escalates those prices at a stipulated rate (e.g., based on retail price projections from the EIA *Annual Energy Outlook*). However, retail rates – and hence the economics of customer-sited PV – are projected to change with increasing PV deployment (Darghouth et al. 2014). In this analysis, we model two separate but interconnected retail-rate feedback mechanisms: fixed-cost recovery and time-varying rate feedback. The factors driving the time-varying rate feedback also affect the partial net metering PV compensation scenario, because exported PV generation is assumed to be compensated at an avoided-cost rate, which depends on the regional PV penetration level. The two net-metering feedback processes are described using a simple conceptual schematic shown in Figure 2. The loop on the left side shows the positive feedback between PV deployment and average retail electricity rates (resulting from recovering the same fixed cost over a decreasing sales base). The other loop, to the right, shows the decreasing coincidence between peak electricity prices and PV generation and its impact on PV deployment for PV customers under time-varying rates. Both these feedback processes are expanded upon in the following sections.

Figure 2. Conceptual schematic showing the two feedback processes between PV deployment and electricity rates included in this analysis

2.3.1 Fixed-cost recovery feedback

When PV is compensated at a retail rate greater than the underlying reduction in the utility's costs from PV, we use a fixed-cost recovery adder to supplement the rates such that the utility still achieves full cost recovery. The fixed-cost recovery adder is modeled at the state level, separately for residential and commercial customers, as follows:

$$A_{FCR} = \frac{(r_{avg} - ac_{PV}) \cdot G_{PV}}{L_{tot} - G_{PV}}$$

where A_{FCR} is the fixed-cost recovery adder for residential or commercial customers, r_{avg} is the average compensation rate for residential or commercial PV customers, ac_{PV} is the calculated avoided utility costs from PV, G_{PV} is the total residential or commercial customer-sited PV generation, and L_{tot} is the total residential or commercial load within the state. The fixed-cost recovery adder, A_{FCR} , is calculated separately for the residential and commercial sectors using the appropriate compensation rate, PV generation, and load values for each sector.

There is considerable debate about how much PV offsets utility costs and about the societal value of PV (Hansen et al. 2013, Denholm et al. 2014, Brown and Bunyan 2014, IREC 2013). We narrowly focus on the value of PV in offsetting utility costs, where the avoided utility costs due to PV generation, ac_{PV} , consists of three components: energy value, capacity value, and miscellaneous value (which includes avoided transmission and distribution losses, transmission and distribution capacity offsets or additions, and other economic cost savings). Our avoided costs in this context excludes any benefits to society not monetized by the utility (e.g., environmental and health benefits); we view this as a lower limit to PV compensation from the utility. It also excludes shorter-term consumer benefits related to lower average wholesale prices.³

We assume energy and capacity value depend on regional PV penetration, where regions are based on EIA's electricity market module zones and PV penetration includes utility-scale and distributed PV.⁴ For the energy value of PV, we assume for simplicity that PV electricity displaces natural gas electric generation as the marginal resources in most regions during PV generation hours. We calculate natural gas generation prices using regional EIA natural gas price projections for the electricity sector and average natural gas plant heat rates (EIA 2014a). We assume PV generation displaces less efficient (and therefore more expensive) natural gas generators at low PV penetrations and more efficient ones at higher penetrations: starting from zero PV penetration, PV displaces natural gas generation that is 10% less efficient than average, and this ramps linearly to displace natural gas generation that is 20% more efficient than average at 20% PV penetration, on an energy basis; these assumptions are based on findings from Mills et al. (2013). To estimate PV penetration, we aggregate PV generation at the regional level to account for the interconnected nature of electric grids. Ultimately, this approach results in the energy value of PV decreasing with increasing regional PV penetration.

We also model the declining capacity value of PV with increasing regional PV penetration. Hoff et al. (2008) modeled the relationship between the capacity value of PV and PV penetration for three electric utilities with different load profiles. Because one driver of PV capacity value is

³ In the short term, PV generation can reduce wholesale electricity prices levels when PV generates owing to the merit-order effect (Sensfuß et al. 2008), hence lowering average wholesale prices, as has been observed recently in Germany and California. However, as unprofitable generators exit the market and older generators retire, new generators will be built such that, in an equilibrium state, all generators are once again profitable. This implies changing wholesale price profiles, but not lower average electricity prices.

⁴ We assumed regional utility-scale PV deployment consistent with U.S. Department of Energy (2012), modeled by NREL's Regional Energy Deployment System. Distributed PV deployment is from this study's SolarDS scenario results.

PV's contribution to generation during peak periods, the capacity credit at low PV penetrations tends to be higher for regions with afternoon (summer) peaking periods than for regions with evening (winter) peaking periods. As PV penetrations increase, the marginal capacity credit of PV falls as the net load peaks shift toward evening hours. We use the three capacity credit curves from Hoff et al. (2008) as well as data on state winter-to-summer peak ratios to interpolate over two curves with the nearest ratio. We then calculate the capacity value of PV at the state level for any given year assuming a capacity cost of \$992/kW for new natural gas generation (EIA 2014b). This approach results in declining PV value with increasing regional PV penetration.

We aggregate all other PV-induced utility cost savings, including avoided transmission and distribution losses as well as deferred (or incurred) transmission and distribution capacity investments and any savings from environmental compliance, into a single "miscellaneous" value adder, which we set to \$0.01/kWh based on an earlier analysis (Darghouth et al. 2010). Though there is increasing consensus that loss savings are reasonably quantifiable, the value of PV resulting from changes in transmission and distribution capacity investments and environmental compliance costs, for example, might increase or decrease with increasing PV penetration, and hence we keep this adder independent of regional PV deployment (Cohen et al. 2015).

In addition to feeding into the fixed-cost recovery and time-varying rate feedbacks, this value of PV estimate, or utility avoided cost, is also used for the partial net-metering scenario: that scenario assumes that all exported PV generation is compensated at a rate representing the sum of the energy, capacity, and miscellaneous value components of PV (calculated for each state based on regional PV penetration). With an export of some PV generation, this mechanism also partially replaces the fixed-cost recovery adder that compensates for the difference between the retail electricity rate and the value of PV under full net metering.

2.3.2 Time-varying rate feedback

For time-varying retail rates, average PV compensation is assumed to change as PV penetration increases, resulting from the shift in the value of PV with penetration. Because the design of time-varying rates varies greatly from one utility to the next, we use existing time-of-use rates as our starting point rather than designing them from the bottom up using standard rate-design methods, because the latter method might produce rates very different from existing ones. Because time-varying rates aim to reflect marginal cost trends, we then adjust those starting-point PV compensation levels to account for changing (net) peak times and levels using the same methods as described earlier.⁵

⁵ We do not adjust demand-charge savings with increasing overall PV penetration. Customer demand charges are often based on non-coincident peak load, in which case demand-charge savings from PV would not change with overall PV penetration. For simplicity, we effectively assume widespread use of non-coincident demand charges. Demand charges may sometimes be based on coincident (net) peak load, however, in which case PV-induced demand-charge savings would decline with increased overall PV penetration. By ignoring this possibility, we understate the magnitude of the time-of-use feedback effect described later.

In particular, for time-of-use or real-time rates, the average compensation for PV generation depends on the coincidence between PV generation and peak price periods. At low PV penetrations, times of PV generation and peak electricity prices coincide reasonably well for afternoon-peaking utilities, hence the value of PV and PV compensation based on time-varying rates can be higher than average rates, as reflected in most time-varying rates available today. As PV penetrations increase, however, the marginal generation cost decreases during the hours when PV generates, driven by the same trends that impact the energy and capacity value of PV as discussed previously⁶; because this is reflected in time-varying rates, we would expect a decrease in PV compensation levels (as found in Darghouth et al. 2014). We therefore model the reduced PV compensation under time-varying rates by decreasing the PV compensation at the same rate as the reductions in energy and capacity value with increasing PV penetration, calculated as described in Section 2.3.1.

3 Results

This section presents our results for the feedback between electricity rates and PV deployment as well as the impact on deployment of varying rate designs and PV compensation mechanisms.⁷

3.1 Feedback between distributed PV deployment and retail electricity rates

In our reference scenario, distributed PV deployment is estimated to increase to roughly 157 GW by 2050. The combined impact of the two modeled feedback mechanisms (fixed-cost recovery and time-varying rate) never increases PV deployment by more than 3% in any single year, versus an otherwise identical scenario without these two feedbacks (Figure 3). As such, at least in the reference case at an aggregate national level, we see no evidence that increased retail electricity prices from distributed PV would accelerate PV adoption significantly.

The dynamics of the counteracting effects underlying this result are critical to understanding the relationship between PV deployment and retail rates.⁸ If we only consider the fixed-cost recovery feedback effect (resulting from the increase in retail rates necessary to recover utility fixed costs), PV deployment increases 8% over the case without any feedback by 2050 (Figure 4). On the other hand, if we only consider the time-varying rate feedback (where bill savings for PV customers decline under time-varying rates due to reduced value of PV), PV deployment decreases by 5% compared with the no-feedback case. In effect, the two feedback mechanisms

⁶ Mills and Wiser (2013) modeled the impact of increased renewables on the economic value of solar at high penetrations in California. Mills and Wiser (2015) also identify strategies that could mitigate this effect, including low-cost bulk storage options or increased customer demand elasticity.

⁷ Figures 2, 6, and 7 show absolute distributed PV deployment, in GW, whereas the other figures in this section show the percentage change in deployment from the no-feedback case or reference scenario results. The 'no-feedback case' was modeled by removing the link between PV deployment and retail rates in the model (present in the 'with feedback' case), and rerunning the reference scenario in SolarDS.

⁸ The two countervailing feedback effects do not sum exactly to the total feedback owing to the minor interaction between the two effects.

largely cancel one another (under our reference case rate-design assumptions at an aggregate national level).

Figure 3. National distributed PV deployment under the reference scenario

Figure 4. Percentage difference between national PV deployment with and without feedback under the reference scenario, broken out by the two feedback effects

The feedback effects differ between residential and commercial customers owing to the different retail rate structures characteristic of each sector. The rate increase resulting from the fixed-cost recovery adder is present for both flat and time-varying rates in the reference scenario. However, customers with time-varying rates experience a counteracting reduction in

PV compensation due to the shifting temporal profile of time-varying rates with increased PV penetration. Most residential customers face flat, volumetric rates in the reference scenario, thus residential deployment increases through 2050 owing to the rate feedback, leveling out at just above 9% over the reference scenario without feedback (Figure 5), when considering both types of feedback (i.e. time-varying rate feedback and fixed cost recovery feedback). In contrast, most commercial customers face time-varying rates in the reference scenario, so total commercial deployment decreases by 15% compared with the no-feedback case. Because commercial PV deployment estimated by SolarDS is much lower than residential deployment, the net effect of the feedbacks over both customer segments is only slightly positive by 2050.

Figure 5. Percentage difference between national PV deployment with and without feedback effects under the reference scenario, broken out by market segment

The results presented to this point are at the national level, and they show the two feedback effects largely cancel each other out in the reference scenario owing to their differential impacts on residential and commercial PV deployment. At the state level, however, feedback effects vary more substantially, as shown in Figure 7 for the year 2050.

For the residential sector, the combined feedback effects increase PV deployment for most states, with a net effect ranging from a 2%–6% (based on the 25th/75th percentile values among states) increase in deployment, compared to an equivalent scenario without feedbacks. The variability among states results from differences in residential PV penetration, underlying average retail rates, and percentages of customers on flat rates. States such as California with higher residential PV penetrations and predominantly flat rates experience much stronger feedback effects. States with a higher percentage of residential customers facing time-varying rates have a lower (or even negative) net feedback effect.⁹

⁹ In Arizona, for example, where a substantial share of residential customers face time-varying rates, the combined effects of the two feedback mechanisms reduce residential PV deployment compared with the no-feedback case.

Because most commercial customers are already on time-varying rates, the two feedback mechanisms yield a net decrease in commercial PV deployment in most states, as a result of the time-varying rate feedback outlined in Section 2.3.2. The magnitude of the commercial customer feedback effects, however, varies substantially across states (i.e., a 9%–22% reduction in deployment, based on the 25th/75th percentile values among states, relative to no feedbacks), because the change in energy and capacity value due to increased regional PV penetration varies widely from one region to the next. States with winter evening peaks have a low PV capacity value, even at low PV levels, hence the reduction in value with PV penetration is not substantial, and the commercial feedback effect is muted.¹⁰

Figure 6. Map of the continental US showing change in PV deployment from the no-feedback case, with the reference scenario.

As shown in Figures 6 and 7, in aggregate considering both feedback effects (i.e. fixed cost recovery and time-varying rate feedbacks), most states have a *negative* total feedback effect, with the median state showing a reduction in cumulative distributed PV deployment in 2050 of 1% relative to the reference case without feedback. This is in slight contrast with Figure 1, which shows a total feedback on a national basis of +2% in 2050. This is because the national results are more significantly influenced by states with large PV markets, particularly California. Regardless, despite widespread literature suggesting a positive feedback effect, our results suggest that the combined effect of the two relevant feedbacks, at least in the reference case, is generally modest and often negative. These state-specific effects can be observed in the map shown in Figure 6.

¹⁰ We do not present state-level results because our focus is on national trends. While our assumptions capture the macro-level dynamics, they do not necessarily capture the state-level idiosyncrasies related to specific rate levels, mixes, or PV adoption factors, because SolarDS is not designed to make state-level projections.

Figure 7. Distribution in feedback effects across U.S. states in 2050, for residential, commercial, and all customers

The results thus far have been for the reference scenario, which assumes residential and commercial rate distributions loosely based on 2013 levels. However, given long-term uncertainties in the rate mix, our scenarios with all customers on a flat rate versus all on a time-varying rate bound results with respect to the rate-mix assumptions (Figure 8). A number of states are considering opt-in time-of-use rates for residential customers, such as California, and a few have made TOU mandatory for commercial customers in some utilities, such as in Connecticut. The details of rate policies, such as grandfathering previously allowed practices or rate switching, will be determined by each state or utility individually, and ultimately will determine whether we have a scenario closer to the all-time varying scenario or not. Current policy discussions would indicate that the end result may have an increasing number of customers under time-varying rates.

For the flat rate scenario in which all residential and commercial customers are served under a flat volumetric rate, feedback increases PV deployment by 3% in 2030 and 8% in 2050. For the time-varying rate scenario in which all residential and commercial customers are served under a time-varying rate, feedback reduces deployment by 6% in 2030 and 25% in 2050. Given the generally expected move, over time, to time-varying rates, these results suggest that the feedback effects increasingly will hinder PV national deployment.

Figure 8. National distributed PV deployment with and without rate feedback for reference, flat rate, and time-varying rate scenarios

3.2 Impact of rate design and PV compensation mechanisms on distributed PV deployment

Whereas the previous section focused on the deployment effects of rate feedbacks, this section shows how various rate designs and PV compensation mechanisms impact total PV deployment, given the presence of those feedback mechanisms. Figure 9 shows the deployment paths for the six scenarios listed in Table 2, with rate feedback effects included, demonstrating that PV deployment is highly sensitive to rate design choices and PV compensation mechanisms.

The flat rate scenario leads to the highest deployment in 2050, and the \$50 residential fixed charge scenario leads to the lowest. Most scenarios follow temporal trends similar to that of the reference scenario (with different magnitudes), but the time-varying rate scenario follows a

different overall trajectory. Specifically, under the time-varying rate scenario, PV deployment is greater than in the reference scenario through about 2030, after which it falls below the reference deployment. This is because, at low PV penetrations, the higher average compensation for PV under time-varying rates boosts PV deployment. However, as regional PV penetration increases and the energy and capacity values of PV erode, compensation for net-metered PV generation also erodes under time-varying rates, leading to lower deployment than under the reference scenario.

Figure 9. National distributed PV deployment by scenario (with rate feedback effects included)

Figure 10 focuses on 2050 cumulative PV deployment for each of the alternative scenarios relative to the reference scenario. Only the flat rate scenario increases deployment compared with the reference scenario; all other scenarios reduce deployment. Were all residential and commercial customers on a time-invariant flat rate with no fixed or demand charges, PV deployment would increase by 5% over the reference scenario owing to the increased average compensation under that simple rate design. Owing to the declining value of PV with increased penetration, the time-varying rate scenario reduces cumulative PV deployment by 22% in 2050 compared with the reference scenario, although time-varying rate structures increase PV deployment through about 2030 (Figure 9).

Both fixed-charge scenarios reduce PV deployment in 2050: a \$10/month charge applied to residential customers reduces total cumulative deployment by 14%, and a \$50/month charge reduces deployment by 61% from the reference scenario. Partial net metering, where PV generation exported to the grid (i.e., not consumed on site) is compensated at a calculated

avoided-cost rate, reduces deployment by 31% from the reference scenario deployment, because in this analysis the assumed avoided cost from PV is lower than the average retail rate, reducing average compensation and increasing the customer's PV payback time.

Figure 10. Change in modeled cumulative national PV deployment by 2050 for various rate design and compensation mechanism scenarios, relative to the reference scenario (with rate feedback effects included)

The distributions of PV deployment differences (compared with the reference scenario) across U.S. states vary substantially by scenario (**Figure 11**). For the two fixed-charge scenarios, the range is relatively small, primarily reflecting differences in the average residential retail rate and average annual customer load across states. For example, states with large annual average customer loads or high average retail rates will see a smaller impact from a given increase in fixed customer charges. The flat rate scenario increases deployment relative to the reference scenario in most states, though only by a modest amount, as a large percentage of customers are already on flat rates.

Compared with the other scenarios, the significance of moving to time-varying rates for PV deployment varies substantially across states, both in the magnitude and direction of the deployment impact. For about 75% of states, switching all customers to a time-varying rate reduces cumulative PV in 2050, relative to the reference scenario. Most affected are states with the highest PV deployment, where the energy and capacity value of PV erodes the most, along

with PV compensation. In regions with low PV penetration, PV compensation under time-varying rates remains higher than the average rate, leading to higher deployment in those states under the time-varying rate scenario than under the reference scenario.

Finally, partial net metering reduces deployment for all states. This is because the retail rate is always greater than the compensation that we assume applies to instantaneous net excess generation, thus reducing deployment from the reference level.

Figure 11. Distribution in deployment differences from the reference scenario for U.S. states in 2050, for all rate design and PV compensation scenarios (with rate feedback effects included)

4 Discussion and Conclusions

In contrast to the increasing concerns about positive feedback linking net-metered PV deployment with higher electricity rates (i.e. the “utility death spiral”), our results suggest that the national net feedback effects of PV are modest and nuanced. There is little change in national PV deployment due to rate feedback under our reference scenario, which includes customers on time-varying rates (mostly in the commercial sector) and flat rates (mostly in the residential sector).¹¹ This is because two feedback effects – a positive one related to fixed-cost recovery and a negative one related to time-varying retail rates – operate in opposing directions. The fixed-cost feedback effect increases cumulative national PV deployment in 2050 by 8%, but the time-varying rate feedback reduces it by 5%. Thus current regulatory and academic discussions that focus solely on the fixed-cost recovery feedback miss an important offsetting feedback mechanism.

¹¹ To reiterate, we did not explore customer defection from the grid due to PV/energy-storage solutions.

The net impact of the two feedback mechanisms varies substantially across customer segments. In general, the prevalence of flat, volumetric electric rates among residential customers ensures a net positive feedback effect with increasing PV deployment, increasing cumulative national residential PV deployment in 2050 by 9% over the reference scenario levels. In contrast, the prevalence of time-varying rates among commercial customers produces a net negative feedback effect, decreasing cumulative national commercial PV deployment in 2050 by 15%. The net effects also vary across states, depending on rate types and levels as well as PV deployment. The total feedback effect considering both residential and commercial customers is –6% to +5% in the vast majority of states and –1% in the median case. Thus the feedbacks reduce PV deployment in most states, and even where they increase deployment the impact is rarely large.

Accounting for these feedback effects, we find that retail rate design and PV compensation mechanisms can impact projected PV deployment dramatically. For example, because time-varying rates capture the declining energy and capacity values of PV at high PV penetration, wider adoption of these rates reduces PV deployment in the long term, in contrast to the stimulation of deployment by time-varying rates at low PV penetration in the nearer term. As mentioned previously, our analysis does not take into account for the potential temporal price smoothing effect of electricity storage resulting from optimal storage dispatch as described in the literature (e.g. Notrott et al. 2013; Ratnam et al. 2015). Taking storage into account would reduce the price differential between peak and off-peak periods, and hence reduce the dampening of PV adoption due to time-varying rates observed in our results. Our analysis suggests that fixed customer charges and compensating PV generation at less than the retail rate – two additional strategies proposed by utilities – also would reduce distributed PV deployment. We estimate that, compared with our reference scenario, cumulative national PV deployment in 2050 could be about 14% lower with a \$10/month residential fixed charge, 61% lower with a \$50/month residential fixed charge, and 31% lower with “partial” net metering. Understanding these deployment impacts will be critical for regulators and other decision makers as they consider potential changes to retail rates – whether to mitigate adverse financial impacts from distributed PV or for other reasons – given the continued role that PV may play in advancing energy and environmental policy objectives and customer choice.

This paper contributes to the value of solar and the cost reflectiveness of PV compensation discussion, but it is not meant to be a comprehensive analysis of the topic. We have found that rate design can have a substantial impact on PV deployment; future research on how rate design leads to over- or under-compensating of solar, and the resulting impact of distributed solar on utility shareholder revenues and return on investment, are essential questions to the future of utility business models and can be informed by the results of this study.

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