Electricity Markets and Policy Group
Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Laboratory

Benefits and costs of a utility-ownership business model for residential rooftop solar photovoltaics

Galen Barbose and Andrew Satchwell

August 2020
This is a pre-print version of an article published in *Nature Energy*
https://www.nature.com/articles/s41560-020-0673-y

This work was supported by the Solar Energy Technologies Office of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Abstract

The rapid growth of rooftop solar photovoltaic systems poses a number of fundamental challenges for the financial stability of regulated electric utilities in the United States. One potential pathway to resolving those challenges would involve allowing utilities to own and operate rooftop solar systems. Here we model the financial performance of a large-scale utility-owned residential rooftop solar program. Over a 20-year period, the program increases shareholder earnings by 2-5% relative to a no-solar scenario; this compares to a 2% loss of earnings when an equivalent amount of rooftop solar is deployed but owned by non-utility parties. Such a program could therefore be highly attractive from the perspective of utility investors. The impacts on utility customers, however, are more mixed, with average bills of non-solar customers increasing by 1-3% compared to the no-solar scenario, similar to the 2% increase under traditional ownership structures.

Introduction

The expansion of rooftop solar photovoltaics (PV) and other distributed energy resources (DERs) has the potential to disrupt existing utility business models, by displacing traditional utility earnings opportunities (Kind 2013) and by creating potentially unsustainable cost-shifting among different groups of utility ratepayers (Cai et al. 2013, Eid et al. 2014). Electric utilities and regulators in the United States have responded in different ways, for example, by creating new electric rate structures for customers with DERs (NARUC 2016, Stanton 2019), by instituting alternate utility revenue models (AEE 2018, Eto et al. 1997, Lowry and Woolf 2016), and by expanding utility product and service offerings into new realms (Blansfield et al. 2017, Satchwell and Cappers 2018a). As an instance of the latter, a growing number of U.S. utilities have experimented with direct ownership of DERs, in many cases focusing specifically on rooftop solar (APS 2019, Dominion Energy 2018, Duke Energy 2019, LADWP 2016, TEP 2019, We Energies 2018).

In terms of its potential appeal to utilities, ownership of DERs first and foremost offers a new earnings opportunity for utility shareholders. But beyond that are a number of other possible advantages, including: improved siting by targeting locations with relatively low interconnection costs or high potential for deferring future network upgrades (Cross-Call et al. 2018); greater visibility and control over DER assets on the part of utility system planners and operators (Blansfield et al. 2017); and the ability to target low- and moderate-income households or other underserved markets (Blansfield et al. 2017). For these reasons and others, utility ownership of rooftop solar may offer one means of addressing the cost-shifting and other equity-related concerns that have often been leveled against the residential solar energy sector. More generally, it could offer a pathway for accelerating the expansion of solar PV and other DERs, by better aligning the deployment of those technologies with utility financial interests and system needs (Neuhauser 2015).

Those advantages notwithstanding, the prospects for wider application of utility-owned rooftop solar remain highly uncertain. Fundamental policy questions exist about the appropriateness of using utility ratepayer funds for what is otherwise a competitive service (Satchwell and Cappers 2018a, Tong and Wellinghoff 2015). Indeed, in some restructured markets, regulated utilities are prohibited by law from owning generation assets, whether large-scale or distributed. Utilities may also be wary of exposing themselves to the risks and liabilities associated with owning equipment on customer rooftops. At the most basic level, however, are questions about whether utility ownership of rooftop solar ultimately represents a compelling financial proposition to utility shareholders and whether the associated costs to utility customers—if implemented at scale—would be acceptable.

This analysis aims to address those latter questions by modeling the effects of a utility-owned residential rooftop solar program on utility shareholder earnings and on the average bills of residential customers without solar (i.e., non-participants). This program differs from more-conventional ownership structures in two important ways. First and most obviously, the equipment is owned by the utility, rather than by the homeowner (HO) or a third-party owner (TPO). The capital costs of those assets are thus added to the utility's rate-base, generating earnings for its shareholders. Second, the rooftop systems are metered separately from the customer's load and connected directly to the utility distribution network. As such, the electricity generated by the rooftop solar systems serves all utility customers rather than offsetting the site host's consumption and electricity bills, as would occur under more-typical remuneration structures like net metering. In exchange for use of their rooftops, the site hosts receive fixed monthly payments or bill credits from the utility—set at a level, in this analysis, to yield roughly the same financial returns as HO or TPO systems.

This work applies quantitative methods to a subject that has otherwise been addressed in the literature primarily at a conceptual level. Some of those studies have proposed specific program designs for utility-owned DERs (Sterling and Vlahoplus 2018) or strategies that utilities might employ to enter this space (Zeneck et al. 2019), while others address utility ownership of DERs within the context of the broader evolution of utility business models and the various regulatory and policy issues therein (Blansfield et al. 2017, Cross-Call et al. 2018, Satchwell and Cappers 2018a). Similar issues have also been taken up within state regulatory dockets, often in response to specific utility proposals (ACC 2017, CPUC 2016, MOPSC 2017, NYPSC 2016).

Base-Case Earnings and Bill Impacts

We begin by considering a utility-owned residential rooftop solar program that ramps up over a 10-year period to ultimately supply 8% of all residential electricity consumption—a level that would put it in the top tier of U.S. utilities in terms of total residential rooftop solar penetration (SEIA & Wood Mackenzie 2019). Our representative utility is based on an investor-owned electric utility located in the southeastern United States; we discuss later how the results may differ for other utilities and regions.

Under our base-case set of assumptions, the utility-owned residential rooftop program boosts shareholder earnings by 3.4% on a 20-year net-present value (NPV) basis, as shown in Fig. 1a. This compares to a 1.7% reduction in shareholder earnings under the more conventional HO or TPO structures. Under both sets of ownership structures, rooftop solar defers utility capital expenditures (CapEx) on large-scale generation assets. Specifically, the solar defers four natural-gas combined-cycle plants by 1-2 years each over the 20-year period following commencement of rooftop solar deployment. This results in some loss of shareholder earnings (the light blue bars in Fig. 1a) due to the later timing of the investment and the time-value of money. In addition, rooftop solar defers a portion of planned CapEx for the utility's transmission and distribution (T&D) system—specifically, that portion driven by peak demand growth—further reducing shareholder earnings (the dark blue bars).

When the utility owns the rooftop solar, the aforementioned sources of earnings erosion are more-than-offset by the additional earnings gained on utility capital investments in rooftop solar (the yellow bar). This largely follows from the fact that rooftop solar is more capital-intensive and has a lower capacity factor than the generation resources it defers. In contrast, under a standard HO/TPO structure, shareholder earnings are further eroded as a result of reduced retail sales (the green bar); indeed, this is the primary source of earnings erosion. This effect often arises under cost-of-service ratemaking when utility rates are set every several years but sales growth lags cost growth in intervening years. Measures that reduce sales growth, such as rooftop solar connected behind the customer meter, amplify this effect. If the rooftop solar is instead connected directly to the utility system, as under our utility-ownership program, this effect becomes moot.

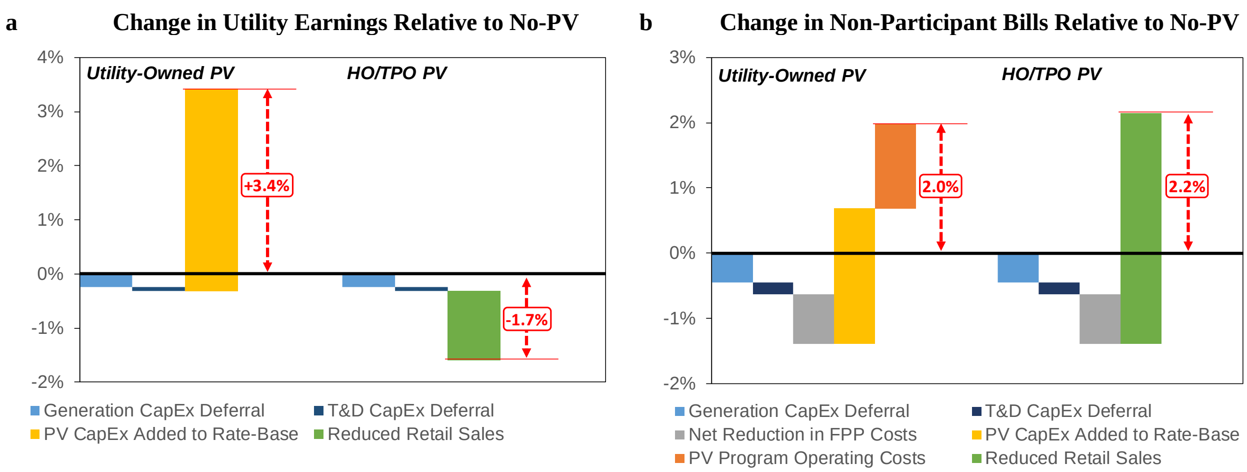

Figure 1. Decomposition of modeled changes in (a) utility shareholder earnings and (b) non-participant bills resulting from rooftop solar PV. Percent changes are measured relative to a counterfactual with no PV, on a 20-year NPV basis, under base-case assumptions. The figures decompose those changes into the six constituent elements, some of which are applicable to only one or the other of the two ownership models.

Turning to the effects on customers (Fig. 1b), it is clear that the added shareholder earnings generated by utility-owned rooftop solar come at some cost to utility ratepayers: average bills for residential customers without solar are 2.0% higher than without any rooftop solar. This is roughly the same bill impact as under a traditional HO or TPO ownership structure (2.2%). In both cases, generation and T&D deferrals reduce customer bills, as do the savings on fuel and power purchase (FPP) costs associated with electricity generation displaced by the output from rooftop solar. However, both ownership structures also involve some offsetting effects that result in a net increase in non-participant bills.

Under the utility-owned rooftop solar program, the effects of CapEx deferrals and avoided FPP costs are more-than-offset by the interest and depreciation expenses associated with the utility investment in rooftop solar, as well as the operating costs of running the rooftop solar program. Under an HO or TPO structure, the cost savings to ratepayers are similarly offset, though for an entirely different reason. Retail electricity rates are essentially the ratio of utility costs to utility sales, and—at least within this particular analysis—rooftop solar reduces retail sales by a proportionately greater amount than it reduces utility costs, leading to higher rates and, in turn, higher bills for non-participating customers.

The sensitivity cases presented later in this analysis explore some of the key drivers and sources of uncertainty associated with the effects and their constituent elements shown in Fig. 1.

Scaling Effects

The residential rooftop solar penetration levels stipulated in the base-case above would, by most standards, represent a highly ambitious program (at least an order of magnitude larger than any existing pilots). Smaller scale programs would yield smaller effects, though not necessarily on a pro-rata basis. Generation CapEx deferrals, in particular, tend to be quite "lumpy", triggered at specific threshold reductions in load growth. Other dynamics—for example, the effects of adding PV CapEx to the utility ratebase and the effects of reduced retail sales—are largely linear in nature.

For the particular utility and conditions evaluated in this analysis, the linear dynamics tend to dominate, and the overall impacts on utility shareholder earnings and customer bills do scale roughly in proportion to PV penetration, at least up to the level considered in the base-case. This can be seen in Fig. 2, which shows shareholder earnings and non-participant bill impacts at both 2% and 8% of residential sales, for both ownership structures. At 2% penetration, no generation deferrals occur; yet, the net effects are more-or-less proportionately lower than the effects at 8% penetration. This linear relationship may break down at higher penetration levels if, for example, high rooftop solar penetration triggers costly upgrades to utility distribution systems or the need for additional flexible generating capacity.

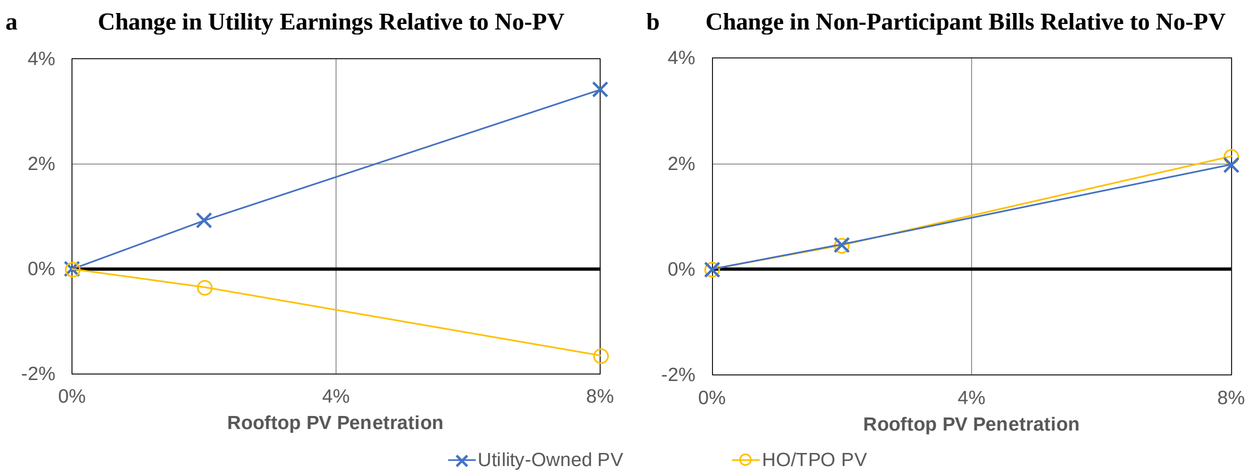

Figure 2. Effects of utility-owned PV and HO/TPO PV on utility shareholder earnings and non-participant bills at varying penetration levels. Percent changes are measured relative to a counterfactual with no PV, on a 20-year NPV basis. The penetration levels along the x-axis represent the steady-state penetration reached in year-10 of the analysis period.

Deferral Value: West-Facing Panels

The deferral value of rooftop solar is driven by factors related to characteristics of both the utility system and the rooftop solar systems. With respect to the latter, one potential benefit of utility ownership is that it may better enable the utility to direct deployment of rooftop solar toward those locations where it provides the greatest deferral value and imposes the lowest integration costs. The clearest example of this strategy among existing pilot programs involves targeting customers with west- or southwest-facing rooftops. Orienting rooftop solar in this manner yields generation profiles that align more closely with the timing of peak load, which then allows for greater deferral of future capital investments to the extent that those investments are driven by peak-load growth.

To test the efficacy of this particular strategy, we consider a scenario in which the utility sites rooftop solar exclusively on west-facing rooftops—as opposed to mostly south-facing panels, as in the base case. Orienting panels westward does further reduce the utility's peak load, though by only 3% more than in the base case. This leads to some modest additional T&D deferrals, but the incremental peak demand reductions are too small to yield any additional large-scale generation deferrals. As a result, shareholder earnings impacts are effectively unchanged from the base case. More significantly, orienting the panels westward reduces solar generation by roughly 14%, which diminishes the savings on FPP costs compared to the base case. As a result, the non-participant bill impacts of utility-owned solar are marginally higher with west-facing panels than with south-facing panels. The results for this scenario, along with several others, are summarized in Fig. 3.

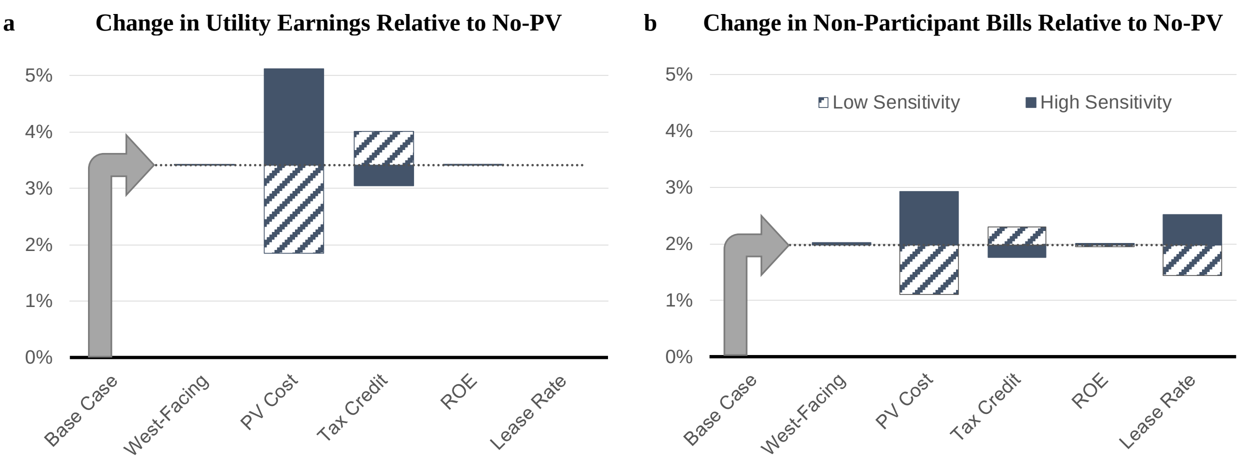

Figure 3. Sensitivity of changes in (a) utility shareholder earnings and (b) non-participant bills resulting from rooftop solar PV. Percent changes are measured relative to a counterfactual with no PV, on a 20-year NPV basis. The penetration levels along the x-axis represent the steady-state penetration reached in year-10 of the analysis period.

The Cost of Rate-Basing Rooftop Solar

As evident in Fig. 1, the shareholder and ratepayer impacts of utility-owned rooftop solar are driven significantly by the effects of adding solar PV CapEx to the utility's rate-base. Those effects are a function of the size of the CapEx, net of any tax credits, as well as the utility's borrowing costs. All of these elements are highly uncertain and can vary significantly from case to case.

First, the installed cost of rooftop PV has declined steeply over the past decade, but it is unclear how sustainable those trends will remain going forward (Barbose and Darghouth 2019). It is also unclear how the costs of rooftop solar might differ under a large-scale utility procurement compared to more-conventional ownership structures. Though the ability to purchase in volume might drive costs down, rate-regulated utilities also face a fundamental structural incentive—the so-called *Averch-Johnson effect* (Averch and Johnson 1962)—to expand capital outlays. To capture these varied uncertainties, Fig. 3 shows utility earnings and bill impacts across a wide but empirically grounded range in residential rooftop solar capital costs. From the lower to the higher end of this solar cost range, utility-owned rooftop solar boosts shareholder earnings by 1.8-5.1% while increasing non-participant bills by 1.1-2.9%, relative to no-PV.

Second, the continued availability of federal investment tax credit (ITC) is uncertain, as is the ability of regulated utilities to fully monetize the value of those credits. As two boundary cases, we consider scenarios where, in the low case, the utility receives no federal tax credit, while in the high case it receives a credit equal to 30% of all capital expenditures on rooftop solar (a continuation of historical levels). Across this range, shareholder earnings are 3.1-4.0% higher than with no-PV, while non-participant bills are 1.8-2.3% higher, where the upper end of those ranges corresponds to the no-tax credit scenario.

Last among the factors related to rate-basing rooftop solar is the utility's borrowing cost, which depends partly on the authorized return on equity (ROE) granted by the utility's regulator. We consider a range in authorized ROEs reflective of recent historical U.S. averages. Those historical average ROEs vary across a relatively narrow range, from 9.25% to 10.25%, as do the results of this sensitivity, as shown in Fig. 3. The utility's authorized ROE is thus a relatively unimportant factor in considering the cost of rate-basing rooftop solar. Performance-based incentives that seek to encourage utility-investment in rooftop solar through higher authorized returns may therefore have limited impact.

Customer Rooftop Lease Payments

Another uncertain and somewhat speculative element in assessing the potential effects of a utility-owned rooftop solar program is the size of the monthly payment or bill credit provided to participating homeowners as compensation for use of their rooftops. Several recent utility pilot programs have offered a $30 monthly payment to participating customers (APS 2019, LADWP 2016). Under a large-scale program such as that contemplated in the present analysis, larger payments might be required to motivate such high levels of participation. At the same time, a utility may be able to reduce these payments over time as it becomes more effective at marketing the program and customers become more comfortable with the arrangement.

Given this uncertainty, we consider a range in monthly lease payments, from $10-50/month. These payments have no impact on utility shareholder earnings, as they are an operating cost recovered through a direct pass-through to retail rates. However, they are a significant driver of non-participant bill impacts. As shown in Fig. 3, varying the monthly lease payments across this range results corresponds to an increase in non-participant bills from 1.4-2.5% relative to a scenario without PV.

Discussion

The results show that utility ownership of residential rooftop solar can offer a potentially significant earnings opportunity to utility shareholders, especially compared to the earnings loss that accompanies behind-the-meter solar under more-typical ownership structures. However, its prospects for lessening the effects of rooftop solar on non-solar customer bills are less clear. Under our base case conditions, non-participant bills are essentially equivalent between utility ownership and other ownership structures, in both cases higher than with no PV. Our findings do, however, suggest some mitigation opportunity if the utility is able to procure rooftop solar at particularly low costs and minimize the monthly lease payments made to homeowners for use of their rooftops. Further mitigation—perhaps even a net reduction in non-participant bills relative to no-PV—may be possible if utility-ownership can facilitate higher value modes of deployment than would occur under traditional ownership structures. Though our analysis of west-facing panels shows limited impact, greater cost savings opportunities may be found through other forms of geo-targeting and through the provision of grid services, which utility ownership could help to facilitate.

To be sure, any mitigation achieved through utility ownership is conditional on how rooftop solar is compensated under traditional ownership structures. In our analysis, the counterfactual assumes full retail rate net metering with primarily volumetric tariffs—an historically accurate but relatively generous compensation scheme that leads to high impacts on both shareholder earnings and non-participant bills. Many U.S. utilities, particularly those with already high rooftop solar penetration, are moving away from this type of rate design and toward less-generous compensation mechanisms. As these shifts occur and the utility shareholder and ratepayer impacts under traditional ownership structures consequently diminish, so too will the relative value of utility ownership.

The results presented in this analysis reflect the characteristics of the modeled utility, and could differ significantly for other utilities and regions. Most importantly, the utility in our analysis has limited solar generation in its portfolio beyond the modeled rooftop solar. A utility with higher background levels of solar generation would likely find greater value in direct utility ownership due to higher solar integration costs (Hirth et al. 2015, Howowitz et al. 2018), which direct ownership might help to manage. For example, such a utility would likely find greater benefit from utility ownership by being able to direct deployment away from distribution feeders already over-saturated with rooftop solar, or by controlling rooftop solar systems to address integration costs associated with other existing or planned solar generation. Utility-owned rooftop solar that defers planned large-scale solar generation would yield greater generation CapEx deferral value than in the present analysis, given the higher up-front cost of utility-scale solar plants compared to the natural gas-fired plants deferred in this study. Another critical feature of the utility modeled in this analysis is its relatively low retail electricity price compared to utilities in other regions. A utility with higher rates would, under traditional rooftop solar ownership structures, see greater revenue loss from reduced retail sales, and thus potentially greater value in utility-ownership structures that avoid those revenue losses.

Finally, though this analysis focuses on rooftop solar, the results are suggestive of the prospects for utility ownership of other forms of DERs. In particular, behind-the-meter battery storage offers greater deferral value, due its dispatchability and wider range of grid services. Those attributes create greater ratepayer bill savings, but also greater erosion of traditional utility earnings opportunities. Allowing direct utility ownership of behind-the-meter battery storage could better align utility shareholder interests with those of their ratepayers, to an even greater extent than this analysis shows to be possible for rooftop solar.

Methods

Model Overview

This analysis relies on Berkeley Lab's FINancial impacts of Distributed Energy Resources (FINDER) model, which was developed to evaluate the effects of DERs on utility shareholders and ratepayers under varying regulatory and market conditions (see Fig. 4). The model has been used and vetted widely, both through direct engagements with state utility regulators (Cappers and Goldman 2009, Cappers et al. 2009, Cappers and Goldman 2010, Cappers et al. 2010) and through independent analytical studies (Satchwell et al. 2011, Satchwell et al. 2015, Satchwell et al. 2017, Satchwell and Cappers 2018b, Satchwell et al. 2019).

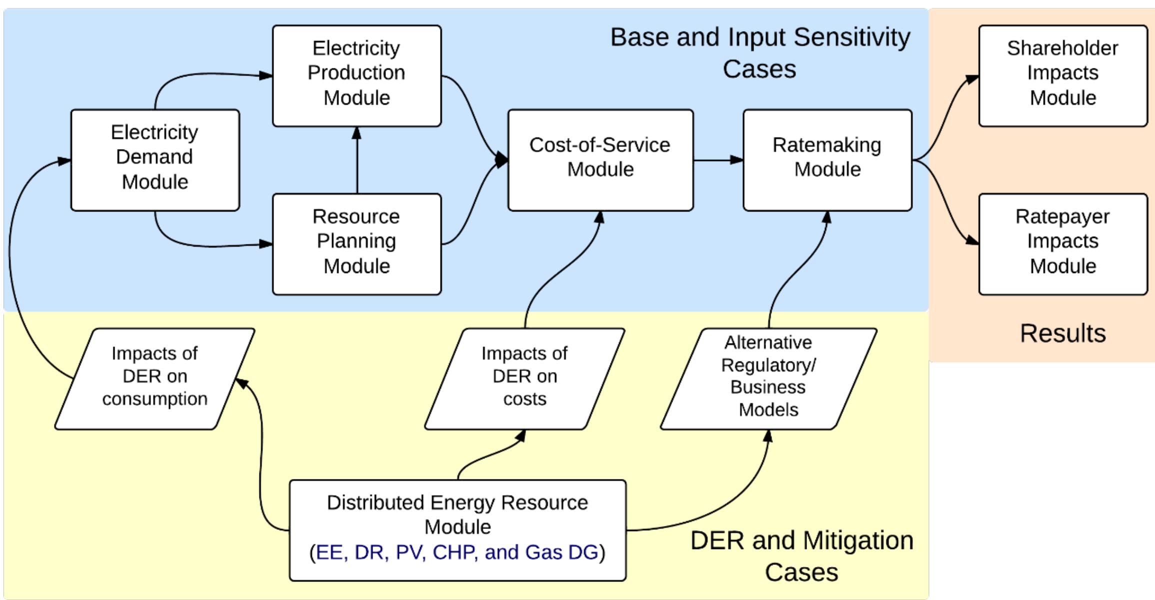

Figure 4. Schematic of Berkeley Lab's FINDER Model

The model requires first specifying an array of assumptions about the individual utility characteristics, as described further below. Based on those inputs, the model then simulates utility costs and revenues over a designated planning horizon (20 years in this study). A unique feature of the model is that it conducts periodic rate cases in which the utility's retail electricity rates are re-set based on the costs and billing determinants in the most recent test year, simulating the manner in which utility rates are typically established. The utility's costs (aka "revenue requirements") are aligned with standard utility accounting categories, including depreciation, return on rate base, interest on debt, taxes, fuel and purchased power costs, among other categories. FINDER simulates these accounting flows and their associated regulatory treatment in order to ultimately compute a series of annual financial metrics, including: the utility's achieved earnings, achieved return on equity, average retail electricity prices, and average customer bills. The latter two metrics are computed separately for each customer class (i.e., residential, commercial & industrial, and lighting).

Adding rooftop solar or other DERs to the model simulation impacts both the utility's costs and its revenues. Key among DER's cost impacts is its ability to defer planned large-scale generation, by virtue of reducing the utility's peak demand growth. This deferral logic begins by specifying the utility's initial generation capital expansion plan.

The generation expansion plan is based on public data from the utility's most recent integrated resource plan, which identifies specific generation units that will be built in specific future years. The model specifies an associated lead-time for each plan, which defines the decision-year in which the utility decides to build the plant. Large-scale generation additions are assumed to be driven primarily to meet peak demand growth. Each planned generation addition therefore has an associated level of peak demand that triggers the decision to build, equal to the peak demand in the year prior to the decision-year. When DERs are added to the utility system and reduce peak demand growth, large-scale generation plants in the utility's capacity expansion plan are deferred until peak demand exceeds the associated trigger level for each plant. Those deferrals are therefore lumpy, with some threshold level of peak demand reduction required in order for any deferrals to occur.

DERs can also defer T&D investments within the model, though those deferrals are represented at an aggregate utility-level, rather than in terms of specific individual investments, as in the case of generation deferrals. The T&D deferral logic begins by specifying annual T&D capital investment in the first year of the planning period as well as the fraction of that total that is driven by peak demand growth (see Table 1). Growth-related T&D CapEx in subsequent years is proportional to peak demand growth in that year. DERs thereby reduce growth-related T&D capital expenditures by virtue of reducing growth in peak demand. This parameterized approach to estimating T&D deferrals is simpler than the approach sometimes taken in detailed "value of solar" studies (Denholm et al. 2014), which involve first cataloguing all of the utility's planned T&D system upgrades, then determining which ones are driven by peak demand growth, and finally determining the extent to which each of those growth-related upgrades is likely to be deferred based on the estimated reduction in peak demand growth for the associated circuit. Those more-detailed studies have often found T&D capacity deferral values ranging from roughly zero to $0.03 per kWh of distributed solar (Hansen et al. 2013, ICF 2018), though a few studies have estimated higher values. By comparison, the approach used in the present study yields a T&D deferral value of $0.02 per kWh of distributed solar, well within the range of the broader literature.

See Satchwell et al. (2017) for additional description of the model structure and computational mechanics.

Utility Characterization

The FINDER model requires a wide array of input parameters related to the utility's physical, financial, operating, and regulatory environment. For this study, we base those assumptions on data from Duke Energy Carolinas, an investor-owned utility located in the southeastern United States. We chose to focus on the southeast for a number of reasons: the region is still dominated by vertically integrated utilities; it has a fairly nascent rooftop solar market; and the regulatory environment is perhaps the most amendable to utility ownership of DERs. The selection of Duke Energy Carolinas, in particular, was driven mostly by data availability, which we sourced from the utility's recent integrated resource plan (Duke Energy 2016) and general rate case filing (Duke Energy 2017), as summarized in Table 1 below. Several modifications to these input assumptions were made for the sake of generalizability, the most significant of which was to substitute two planned nuclear plant additions with an equivalent amount of planned combined cycle gas turbine (CCGT) capacity. Importantly, the utility characterization used in this study is not meant to represent Duke Energy Carolinas.

Table 1. Utility Characteristics

Parameter	Value or Assumption
Year-1 sales and peak demand	16,104 GWh (sales), 3,294 MW (peak)
Year-1 average all-in residential rate	$0.0943/kWh
Year-1 generation mix	700 MW Nuclear, 2000 MW Coal, 400 MW CCGT, 700 MW CT
Year-1 revenue requirements	$1,489 million
Hourly load shape	Based on 2017 data for Duke Energy Carolinas
Sales and peak demand growth rates	1.04%
Generation capacity additions	300 MW CCGT (2022), 100 MW CT (2024), 1500 MW CCGT (2026 & 2028)
Year-1 T&D CapEx	$111 million
Percent of T&D CapEx driven by load growth	33%
Average T&D losses	4.0%
Residential rate design	Flat, volumetric rates (90% energy / 10% fixed monthly customer charge)
Rate case frequency	Every 3 years
Authorized ROE	9.75%

Solar Resource Modeling

We modeled hourly solar generation using the National Renewable Energy Laboratory's System Advisor Model (SAM), based on 2017 weather data for Columbia, South Carolina. We ran simulations across a range of panel orientations, and the final hourly profile used in the FINDER analysis was based on a weighted average across those orientations, with weights based on the observed distribution of residential PV system orientations from Barbose and Darghouth (2019). The resulting generation profile corresponds to a capacity factor of 19.4%.

We assume that total residential solar deployment ramps up linearly over 10 years until it reaches 8% of year-10 residential retail electricity sales. Given the capacity factor noted above and forecasted residential sales, cumulative residential rooftop solar installations reach 353 MW_{ac} (424 MW_{dc}) in year-10, and remain constant at that level thereafter. We assume each residential rooftop system is 7.4 kW_{dc} in size, based on median system sizes in the region, as documented in Barbose and Darghouth (2019). This yields a total of 57,295 rooftop solar customers in year-10. Under the scenarios where rooftop solar is owned by the host customer or some third party, we assume that the systems are installed behind the customer meter, and that the host customer is compensated under a typical net metering arrangement, whereby each kWh generated offsets and equivalent amount of billed retail electricity sales.

Utility-Owned Rooftop Solar Program Design

The utility-owned rooftop solar program is based loosely on pilot programs developed by Arizona Public Service and the Los Angeles Department of Water and Power, in which utility-owned rooftop systems are connected directly to the utility-side of the host-customer meter and therefore provide no direct reduction in the host customer's billed consumption. Instead, the customer is offered a monthly payment for use of its rooftop. In addition to the cost of monthly lease payments, which accumulate over time as more customers join the program, the utility also bears ongoing operating & maintenance costs and program administration costs, as well as capital costs associated with procuring systems over the initial 10 years when new customers are enrolled. These and other key assumptions are detailed in Table 2 below.

Our analysis also includes a limited set of sensitivity cases, intended to focus primarily on uncertainties and discretionary aspects of how the utility-owned rooftop solar program is implemented. These sensitivity cases are defined and explained further in Table 3 below.

Table 2. Key Parameters for Modeling the Utility-Owned Rooftop Solar Program

Parameter	Value	Notes and Data Source
Year-1 PV CapEx	\$2.50/W (nominal)	We assume that the utility would be able to procure rooftop PV at relatively low prices, compared to an individual homeowner. Based on Barbose and Darghouth (2019), the 20th percentile value among residential system prices in 2018 was roughly \$3.00/W. Of that total, however, roughly \$0.50/W is associated with customer acquisition costs which are accounted for separately in this analysis as part of the program administration costs.
Annual decline in PV CapEx	6% (real)	This is the average rate of decline for residential rooftop solar since 2013, during which time prices have declined at a relatively steady pace (Barbose and Darghouth 2019).
Year-1 PV O&M	\$20/kW-yr (nominal)	This is the default value in SAM for residential rooftop solar.
Monthly customer lease payment	\$30/month (nominal)	This is roughly the monthly lease payment rate yields the same NPV to the site host as the BAU PV case, as determined through SAM modeling runs.
Year-1 Program admin. costs	\$500/participant-yr (nominal)	Based on typical program administration costs for residential HVAC energy efficiency programs (Grevatt et al., 2017; Hoffman et al., 2018). This program was chosen as the closest available proxy, given the paucity of data on actual utility-rooftop solar program administration costs.
Investment tax credit	30% through 2019, declining to 10% in 2022 and beyond	Based on current tax credit schedule; we do not consider "safe harbor" provisions.
Capacity credit	31.9%	Calculated from the utility load shape and PV production profile; equal to the reduction in peak-hour demand in year-10, when PV penetration reaches its maximum.

Table 3. Key Parameters for Modeling the Utility-Owned Rooftop Solar Program

Sensitivity		Value	Notes and Data Source
Panel Orientation		All systems facing due-west	
PV CapEx	Low	$1.5/W in Year-1, 7%/yr. decline (real)	The low-case reflects the U.S. Department of Energy's previous 2020 cost target for residential PV, while the high-case corresponds roughly to median residential prices in 2018 (Barbose and Darghouth 2019).
	High	$3.5/W in Year-1, 5%/yr. decline (real)	
ITC	Low	10% ITC applied to all PV CapEx	The low-case reflects a scenario where the utility-owned PV program is initiated after ITC phase-down has fully occurred, while the high-case reflects a case where the ITC is extended at current levels.
	High	30% ITC applied to all PV CapEx	
ROE	Low	50 basis points below base ROE	Reflects the ~100 basis point historical range in average authorized ROEs for U.S. electric utilities from 2009 to the present (S&P Global Market Intelligence 2018).
	High	50 basis points above base ROE	
Lease Rate	Low	$10/month	Intended to represent a plausible range in the level of customer compensation required to achieve the targeted penetration levels in this study, which ramp up to 8% of residential retail sales by year-10.
	High	$50/month	

Data Availability

Key data and assumptions are identified in the Methods section in Tables 1-3. Additional utility financial and planning data used to populate the model are derived from publicly available regulatory filings by Duke Energy Carolinas, and can be downloaded through the South Carolina Public Service Commission's electronic docket system at https://dms.psc.sc.gov/Web/Dockets, using the application numbers provided in the references below (Duke Energy 2016 and 2017). Additional data that support the findings of this study are available from the corresponding author upon reasonable request.

Code Availability

Solar generation profiles were developed using the National Renewable Energy Laboratory's System Advisor Model, which is publicly accessible at https://sam.nrel.gov/. Utility shareholder and ratepayer impacts of alternate solar ownership models were developed using Berkeley Lab's FINDER model. That model, written in Analytica, is available from the corresponding author upon request.

References

ACC. 2017. *In the matter of the application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, to approve rate schedules designed to develop such return*. Arizona Corporation Commission, Decision No. 76374, Docket E-01345A-16-0036.

AEE. 2018. *Utility Earnings in a Service-Oriented World: Optimizing Solutions for Capital- and Service-Based Solutions*. Advanced Energy Economy Institute, January.

APS. 2019 Arizona Public Service "Solar Partners Program" webpage. Accessed February 2019. https://www.aps.com/en/ourcompany/aboutus/investmentinrenewableenergy/Pages/solar-partner.aspx?src=solarpartner

Averch, H. and Johnson, L. (1962) The Behavior of the Firm Under Regulatory Constraint. *The American Economic Review*. 52(5): 1052-1069.

Barbose, G. and N. Darghouth. 2019. *Tracking the Sun: 2019 Edition.* Berkeley, CA: Lawrence Berkeley National Laboratory.

Blansfield, J., L. Wood, R. Katofsky, B. Stafford, D. Waggoner, and National Association of State Utility Consumer Advocates. 2017. *Value-Added Electricity Services: New Roles for Utilities and Third-Party Providers*. Berkeley, CA: Lawrence Berkeley National Laboratory.

Cai, D., S. Adlakha, S. Low, P. DeMartini, and K. Chandy. 2013. "Impact of Residential PV Adoption on Retail Electricity Rates." *Energy Policy* 62 (2013): 830–843.

Cappers, P., C. Goldman, M. Chait, G. Edgar, J. Schlegel, and W. Shirley. 2009. *Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility*. Berkeley, CA: Lawrence Berkeley National Laboratory.

Cappers, P. and C. Goldman. 2009. *Empirical Assessment of Shareholder Incentive Mechanisms Designs under Aggressive Savings Goals: Case Study of a Kansas "Super-Utility."* Berkeley, CA: Lawrence Berkeley National Laboratory.

Cappers, P., A. Satchwell, C. Goldman, and J. Schlegel. 2010. *Benefits and Costs of Aggressive Energy Efficiency Programs and the Impacts of Alternative Sources of Funding: Case Study of Massachusetts*. Berkeley, CA: Lawrence Berkeley National Laboratory.

Cappers, P. and C. Goldman. 2010. "Financial Impact of Energy Efficiency under a Federal Combined Efficiency and Renewable Electricity Standard: Case Study of a Kansas 'Super-Utility.'" *Energy Policy* 38 (8): 3998–4010.

CPUC. 2016. *In the Matter of the Application of Southern California Edison Company (U338E) for Approval of its Charge Ready and Market Education Programs - Decision Regarding Southern California Edison Company's Application for Charge Ready and Market Education Programs*, California Public Utilities Commission, Application 14-10-014, Decision 16-01-023, January 25.

Cross-Call, D., R. Gold, L. Guccione, M. Henchen, and V. Lacy. 2018. *Reimagining the Utility: Evolving the Functions and Business Model of Utilities to Achieve a Low-Carbon Grid*. Rocky Mountain Institute.

Denholm, P., R. Margolis, B. Palmintier, C. Barrows, E. Ibanez, L. Bird, and J. Zuboy. 2014. *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*. Golden, CO: National Renewable Energy Laboratory.

Dominion Energy. 2017. Virginia Solar Pathways Project, December 4, 2017 Report.

Duke Energy. 2016. *2016 Duke Energy Carolinas Integrated Resource Plan*. Submitted to the Public Service Commission of South Carolina, Docket No. 2016-10-E.

Duke Energy. 2017. *Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*. Submitted to the North Carolina Utilities Commission, Docket No. E-7, Sub 1146.

Duke Energy. 2018. *Petition of Duke Energy Indiana, LLC for Approval of a Solar Services Program Tariff, Rider No. 206, and Approval of Alternative Regulatory Plan ("ARP") and Declination of Jurisdiction to the Extent Required under Ind. Code 8-1-2.5-1, ET. SEQ*. Indiana Utility Regulatory Commission, Cause No. 45145, Application filed September 25, 2018.

Eid, C., J.R. Guillén, P.F. Marína, and R. Hakvoort. 2014. "The economic effect of electricity net-metering with solar PV: Consequences for network cost recovery, cross subsidies and policy objectives." *Energy Policy*, 75(December 2014), pp. 244-254.

Eto, J. S. Stoft, and T. Belden. 1997. "The theory and practice of decoupling utility revenues from sales." *Utilities Policy*, 6 (1), pp. 43-55

Kihm, S., P. Cappers, and A. Satchwell. 2016. *Considering Risk and Investor Value in Energy Efficiency Business Models*. American Council for an Energy-Efficient Economy Summer Study, August.

Hansen, L, V. Lacy, and D. Glick. 2013. *A Review of Solar PV Benefit and Cost Studies, 2nd Edition*. Rocky Mountain Institute.

Hirth, L., F. Ueckerdt, and O. Edenhofer. 2015. "Integration Costs Revisited – An Economic Framework for Wind and Solar Variability." *Renewable Energy* 74 (February 2015): 925–39.

Horowitz, K.A.W., B. Palmintier, B. Mather, and P. Denholm. 2018. "Distribution system costs associated with the deployment of photovoltaic systems." *Renewable and Sustainable Energy Reviews* 90 (July 2018: 420-43.

ICF Consulting. 2018. *Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar*. Report prepared for the U.S. Department of Energy.

LADWP. 2016. *Solar Rooftops Program Guidelines Community Solar: Effective November 2, 2016.* Los Angeles Department of Water and Power.

Lowry, M.N. and T. Woolf. 2016. *Performance-Based Regulation in a High Distributed Energy Resources Future*. Berkeley, CA: Lawrence Berkeley National Laboratory.

MOPSC. 2017. *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of a Tariff Setting a Rate for Electric Vehicle Charging Stations -*

Report and Order, Public Service Commission of the State of Missouri. Case ET-2016-0246, April 19.

NARUC. 2016. *Distributed Energy Resources Rate Design and Compensation: A Manual Prepared by the NARUC Staff Subcommittee on Rate Design*. National Association of Regulatory Utility Commissioners.

Neuhauser, J. 2015. "Allowing Utilities to Compete in the Distributed Energy Resources Market: A Comparative Analysis." *LSU Journal of Energy Law & Resources* (3)2: 375-403.

NYPSC. 2016. *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework*. New York Public Service Commission, Case Number 14-M-0101.

S&P Global Market Intelligence. 2018. "Average U.S. Electric, Gas ROE Authorizations in H1'18 Down From 2017." August 2, 2018.

Satchwell, A., Cappers, P. and Goldman, C. 2011. "Carrots and sticks: A comprehensive business model for the successful achievement of energy efficiency resource standards." *Utilities Policy*, 19(4), 218-225.

Satchwell, A., A. Mills, and G. Barbose. 2015. "Regulatory and ratemaking approaches to mitigate financial impacts of net-metered PV on utilities and ratepayers." *Energy Policy*, 85(October 2015), pp. 115-125.

Satchwell, A., P. Cappers, and C.A. Goldman. 2017. *Financial Impacts of a Combined Energy Efficiency and Net-Metered PV Portfolio on a Prototypical Northeast Utility*. Berkeley, CA: Lawrence Berkeley National Laboratory.

Satchwell, A. and P. Cappers. 2018a. *Evolving Grid Services, Products, and Market Opportunities for Regulated Electric Utilities*. Berkeley, CA: Lawrence Berkeley National Laboratory.

Satchwell, A. and Cappers, P. 2018b. Customer Bill Impacts of Energy Efficiency and Net-Metered Photovoltaic System Investments. *Utilities Policy*, 50:144-152.

Satchwell, A., P. Cappers, J. Reneses, W. Gorman, and G. Leventis. 2019. *Financial Impacts of Net-Metered Distributed PV on a Prototypical Western Utility's Shareholders and Ratepayers*. Berkeley, CA: Lawrence Berkeley National Laboratory.

SEIA & Wood Mackenzie. 2019. *U.S. Solar Market Insight: 2019 Year-in-Review*. Solar Energy Industries Association & Wood Mackenzie Power and Renewables.

Stanton, T. 2019. *Review of State Net Energy Metering and Successor Rate Designs*. National Regulatory Research Institute.

Sterling, J. and C. Vlahoplus. 2018. *Lighting the Way to Utility DER Ownership*. Solar Electric Power Association Member Brief.

TEP. 2019. Tucson Electric Power "Residential Solar Program" webpage. Accessed February 2019. https://www.tep.com/residential-solar/#nogo

Tong, J. and J. Wellinghoff. "Should utilities be allowed to rate base solar?" *Utility Dive*. May 11, 2015.

We Energies 2018. "Application to the Wisconsin Public Service Commission for the Solar Now Pilot and the Dedicated Renewable Energy Resource Pilot." Filed in Wisconsin Public Service Commission Docket Number 6630-TE-102.

Zenneck, J., M. Bader, T. Baker, and H. Rubel. 2019. *The M&A Way into Distributed Energy*. Boston Consulting Group.

Acknowledgements
This analysis was funded by the U.S. Department of Energy Solar Energy Technologies Office under Contract No. DE-AC02-05CH11231.