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# Customer Bill Impacts Among Energy Efficiency and Net-Metered PV Participants and Non-participants

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**Abstract**

Utility regulators and policymakers are concerned about potential increases in retail rates driven by energy efficiency (EE) programs and distributed solar photovoltaic (PV) systems, which may adversely affect utility customers that do not invest in these technologies (i.e., non-participants) and more so than those that do (i.e., participants). We assess customer bill impacts of illustrative EE programs and net-metered PV systems for a prototypical northeast utility. We find that the timing of customer EE or PV investments matters and that modest energy savings may fail to yield financial benefits sufficient to offset concomitant increases in retail rates.

**Keywords**

Utility Regulation; Customer bills; Rate design

## 1. Introduction[1]

Customer-funded energy efficiency (EE) spending in the United States almost tripled from 2007 to 2014 (CEE, 2016; CEE, 2008) and EE programs in 16 states each generated more than a 1.0% annual reduction in utility sales in 2015 (Gilleo et al., 2015).[2] These savings levels will likely increase with spending on EE programs projected to double again from 2010 levels by 2025 (Barbose et al., 2013). Similarly, though at a smaller scale,[3] distributed solar photovoltaic (PV) penetration is projected to reach 2.9% of U.S. retail electric sales in 2020,

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[1] *Abbreviations:* AEV – aggressive EE/PV; BAU – business-as-usual; C&I – commercial and industrial; DER – distributed energy resource; DOE – Department of Energy; EE – energy efficiency; LED – light emitting diode; NE – northeast; NEM – net energy metering; PV – solar photovoltaic; RECS – residential energy consumption survey

[2] CEE (2008) reported electric and gas utility budgets of $2.6B for energy efficiency in 2007 and CEE (2016) reported $6.9B in spending in 2014. We exclude load management/demand response program spending.

[3] Barbose et al., (2016) estimated the cumulative impacts of EE to be 15 times greater than the cumulative impacts of distributed PV through 2014.

with several states expected to see penetration rates in excess of 5.0% (GTM and SEIA, 2015). Many of the states with greater EE savings levels (i.e., greater than 1.5% per year) are also expected to see higher PV penetration rates. While EE programs and distributed solar PV provide numerous utility, customer, and societal benefits (including utility cost reductions, lower customer bills, and achievement of clean energy public policy goals), they also contribute to potential stagnant or declining retail sales for electric utilities and put upward pressure on retail electricity rates in order to meet revenue requirements (Moskovitz, 1989; Eto et al., 1994; Moskovitz et al., 2000).

Utility regulators and policymakers are concerned about potential increases in retail rates, which may adversely affect customers that do not invest in EE measures or PV systems (i.e., non-participants) and more so than customers that do (i.e., participants). This potential for cost shifting has led to some hesitance about expanding ratepayer-funded EE program budgets or policies to advance the adoption of distributed generation (e.g., net energy metering).

Analyzing and understanding changes in utility rates and customer bills can inform the debate about the merits of promoting expanded adoption of EE and PV (SEE Action, 2011). Specifically, analyzing bill impacts on participating and non-participating customers illustrates how the outcomes associated with achieving broader societal goals may vary among distinct customer groups. In addition to assessing net financial benefits of clean energy policies, policymakers and regulators are also concerned about the distributional financial effects of alternative regulatory and ratemaking approaches on different groups of customers, including low-income customers.

The limited work to date quantifying the financial implications of EE and PV for both utility shareholders and ratepayers has focused on these investments in isolation (e.g., Cappers and Goldman, 2010; Cai et al., 2013; Satchwell et al., 2015a; Boero et al., 2016). However, many states with the highest level of savings from EE programs also have high rates of distributed solar PV adoption. For example, four of the top-ten ranked states for energy efficiency (CA, MD, NY, and MA) have PV penetration rates that are well above the national average (Gilleo et al., 2015; GTM and SEIA, 2015).[4]

A number of studies have looked at the impacts of EE or distributed solar PV on participant and non-participant bills, but never jointly. Several studies have examined customer bills under net energy metering (NEM) for distributed solar PV as compared to other compensation mechanisms for generation sold back to the electricity grid (such as feed-in-tariffs, value-of-solar tariffs, and wholesale market prices). These studies primarily focus on residential customers and are based on state-specific rates and policies (e.g., Darghouth et al., 2011; Darghouth et al., 2013). Woolf (2013) analyzed customer bill impacts among EE participating customers with quantitative examples illustrating foundational concepts.

This analysis takes into account several different perspectives on the types and timing of EE and distributed solar PV investments representing some of the key sources of variability in bill impacts. Specifically, we assess participating customer bills among cohorts representing different initial energy and peak demand levels. We also assess bills for customers that chose to invest earlier versus those that invest later in the analysis period. The choice of investment (EE measures or PV system) and the magnitude of the associated energy and demand savings also play a pivotal role in customer bill impacts. Finally, regulatory and ratemaking strategies that are intended to mitigate the effect of declining sales on a utility's ability to fully recover its revenue requirements, including fixed costs (IEI, 2014; NCCETC, 2016), may have varying bill

[4] Gilleo et al. (2015) ranked states by their level of efficiency savings and presence of enabling policies.

impacts across the customer cohorts.

We note several key boundaries of the study scope and its methodology to distinguish our research from cost-benefit studies and to ensure that the findings are appropriately interpreted and applied. First, the present study is not a detailed analysis of the value of EE or distributed solar PV. In this study, we use a financial model that contains a relatively high level of detail in its representation of utility ratemaking and cost recovery processes, but less detail in its representation of the physical utility system. As a result, the impacts of EE or distributed solar PV on utility cost of service are based on a coarser set of assumptions than what might be possible with integrated and dynamic models of utility operations, including those used for planning.[5]

Second, the analysis is focused narrowly on changes in customer utility bills under existing models of utility regulation in the Northeast United States. Our analysis does not consider any broader societal benefits of EE and distributed PV (e.g., reduced emissions, economic development, and energy security). Furthermore, by limiting the scope of our analysis to net-metered PV, we do not address potential impacts to participating and non-participating customers that may occur under other compensation schemes, such as feed-in tariffs, value-of-solar tariffs, and wholesale market prices.

## 2. Approach

We quantify customer electricity bills based on changes in utility load, costs, and collected revenues for a northeastern, distribution-only utility that achieves aggressive EE

[5] Satchwell et al. (2015a) included numerous sensitivity analyses to examine how the financial impacts of distributed PV would vary with alternate assumptions related to avoided costs.

savings and PV penetration levels driven by state clean energy policies compared to a business-as-usual (BAU) case. Our goal is to quantify the diversity of bill impacts on the present value of annual electric bills during the ten-year analysis period (2017-2026) based on a customer's decision whether or not to invest in EE measures or PV systems.

We chose to model a northeastern (NE) utility because the region has historically achieved high levels of energy savings from EE programs and substantial customer investments in their own PV systems. Six states in the region (Connecticut, Maine, Massachusetts, New York, Rhode Island, and Vermont) adopted EE resource standards that obligate utilities to achieve specified savings goals (Gilleo et al., 2015). Five NE states (Massachusetts, Vermont, Delaware, New Jersey, and New Hampshire) have relatively high PV penetration levels that are expected to significantly increase over the next five years (GTM and SEIA, 2015). All NE states have NEM policies in place in addition to various state-level incentives for distributed generation, which are key drivers for PV deployment (NCCETC, 2016).

This analysis uses annual class-level retail rates for energy (¢/kWh), demand ($/kW), customer ($/customer), and balancing accounts (¢/kWh) charges derived from a pro-forma financial model that takes into account a prototypical NE utility's financial, operational, and regulatory characteristics as well as class-level rate design. For the NE utility, we modeled the impacts of an aggressive EE and distributed solar PV portfolio, estimating changes to utility costs, revenues, retail rates, and shareholder profitability. While EE and net-metered PV result in impacts to utility shareholders, we limit our analysis herein to rate and bill impacts.[6]

The retail rate impacts used in this analysis were first assessed under a BAU scenario assuming a modest amount of energy savings from EE programs and PV systems pursuant to

[6] Readers interested in impacts on utility shareholder profitability are referred to Satchwell et al. (2017).

representative policies in several New England states, which establishes a reference point against which to measure impacts of a more aggressive EE and distributed solar PV (AEV) portfolio.

The AEV portfolio was based on goals associated with extrapolated EE savings and forecast distributed solar PV adoption for Massachusetts, which produced significant declines in the NE utility's forecast retail sales and peak demand (see Table 1 and Table 2). The AEV portfolio also produced reductions in NE utility total costs by 3% based on the modeled relationships among electricity sales, peak demand, and the utility's fixed and variable costs. In aggregate, total collected revenues from customer bills decrease by 5% for the AEV case compared to the BAU case.

All-in average retail rates for the NE utility in the AEV scenario increase by about 3% each year during the analysis period compared to a 2% annual average increase in all-in average retail rates in the BAU scenario. Figure 1 shows the all-in average retail rates in the BAU and AEV scenarios for the ten-year period we used to calculate customer bill impacts and the more dramatic increase in all-in average retail rates in the AEV scenario, in particular. This significant increase in average all-in retail rates in the AEV scenario is driven by several factors. First, the utility's revenues decline more than their costs because the combined EE and PV portfolio reduces only a small portion of the NE utility's non-fuel costs, which tend to be fixed in the short term. Second, the utility's revenue requirements must be spread over significantly lower retail sales.[7]

*2.1 Customer cohort assumptions*

We develop an analytical approach intended to be illustrative of a range of potential

[7] See Satchwell et al. (2017) for a characterization of the NE utility, a review of modeling assumptions, and a discussion of the key drivers for changes in utility sales, demand, costs, and revenues.

customer bill impacts. We do not model the entire population of customers for the NE utility but instead develop representative customer cohorts that are likely to participate in various types of EE programs or invest in PV systems.

We first create sub-populations of customers that, based on their usage profiles relative to the class average, are eligible to participate in a single EE program (namely, a commercial rebate program targeted at smaller business or industrial customers, a custom rebate program targeted at large commercial and industrial (C&I) customers, a residential low-income program, and a residential consumer product rebate program) or install a PV system (see Figure 2 and Figure 3).[8] Each cohort's unique EE or PV investment generates average annual energy and billing demand savings expressed as a percentage of usage for the class-average customer. For example, we assume that the typical low-income residential customer of the NE utility uses less electricity than the average residential customer (specifically, 83% of the residential class average). To characterize bill impacts of participating customers in a low-income program, we also assume that the typical low-income residential customer reduces their annual energy and non-coincident peak demand level by 10% based on the measures installed in that program. Similarly, we assume that all residential customers eligible to participate in an EE product rebate program (e.g., LED lighting measures) have an initial usage level that is comparable to the class average (i.e., 100% of the residential class average) and reduce their annual energy and non-coincident peak demand by 2.3% based on measures installed under that program. For residential customers that have the potential to install a solar PV system, we assume that it is sized to reduce their total annual energy usage by 100% but does not affect their billing demand (Darghouth et al., 2017). We assume that participation in a specific EE program or investment

[8] This is a simplifying assumption that allows us to illustrate and isolate the impacts of decisions by participants to invest in specific EE or PV technologies. Customers of various consumption levels may invest in both.

in a solar PV system is mutually exclusive and independent. In other words, a participating customer only has the option of investing in EE measures offered in a specific EE program or installing a PV system.

Illustrative annual energy and demand savings EE programs and PV systems come from several sources. We primarily relied on the 2014 and 2015 reports of Massachusetts EE program administrators for typical EE program savings. We also reviewed the 2009 residential energy consumption survey (RECS), the most recently available dataset, to estimate average low-income energy consumption across the NE region (EIA 2009). PV system savings were assumed at 100% of the class-average residential customer's annual energy use because net-metering arrangements incentivize investment in solar systems to offset annual energy use. We acknowledge that this is an upper-bound assumption as many jurisdictions do not allow customers to size PV systems to exceed average annual energy consumption. Estimates of C&I PV system energy savings are from Davidson et al. (2015), which calculates average system size based on available roof space and other assumptions. PV system demand savings come from Darghouth et al. (2017) simulating customer class PV system profiles and their coincidence with utility system peak.

*2.2 Representing the Timing of Customer EE and PV Investments*

The timing of EE and PV investment matters for calculating customer bills as portfolio and rate effects of EE and PV effects are cumulative. To account for timing, we differentiate customer cohorts based on when the participation decision is made to meet the AEV savings goals, as follows:

- **Non-Participants**. These customers do not invest in EE or PV at any point during the analysis period. We compare utility bills for a non-participating customer under BAU rates with a non-participating customer under AEV rates. Thus, we calculate bill impacts using the difference in rates in the BAU and AEV scenarios, *absent* the effects of any EE or PV on annual energy usage and demand. Results for non-participants, therefore, represent the effects of rate increases associated with the achievement of the AEV savings goals on the same annual energy and demand (i.e., non-participants face higher rates but do not alter consumption).

- **Prior Participants**. These customers invested in EE or PV prior to the analysis period. We compare utility bills for a participating customer under BAU rates with a participating customer under AEV rates. Thus, we calculate bill impacts using the difference in rates in the BAU and AEV scenarios, *inclusive* of the effects of EE or PV on annual energy and demand. Results for prior participants, therefore, represent the effects of rate increases associated with the achievement of the AEV savings goals as well as the energy and demand savings from investments made by prior participants.
- **New Participants**. These customers invest in EE or PV at some point during the analysis period. We compare utility bills for a non-participating customer under BAU rates with those of a participating customer under AEV rates. We calculate the bill impacts as the difference in utility bills in the BAU vs. AEV scenarios accounting for (1) annual energy and demand savings that result from EE or PV investments by new participants, and (2) changes in annual rates between BAU and the AEV case. Results for new participants, therefore, represent the effect of the customer's decision to make an EE or PV investment during the analysis period.

We assume that annual energy and demand savings from the EE programs and PV systems persist at the same level after the investment is made through the remainder of the analysis period. Conceptually, this means that we assume that the prototypical NE utility achieves its aggregate savings goals over time by simply reaching more customers in that class rather than achieving deeper savings on a per-customer basis.

Figure 4 shows the methodology to calculate annual bills for the different cohorts of customers based on the timing and impact of their investment decisions. Specifically, customer bills for each of the cohorts are derived annually by multiplying each rate component (i.e., ¢/kWh, $/kW, and $/customer) by its respective billing determinant (i.e., per customer annual kWh retail sales and per-customer annual kW peak demand) where the customer's utility bill reflects the sum of all revenue collected via base rates and balancing accounts. For both the residential and C&I customer classes, although not explicitly shown, balancing account costs are collected via an energy charge and included in the energy portion of a customer's annual bill. It is important to note that we assume all customers within a rate class (e.g., residential customers) face the same retail rates, regardless of EE or PV investment. For PV customers, we assume a NEM compensation policy is in place that allows annual net metering credits from excess PV production to offset an equal amount of annual energy consumption with no carryover from one year to the next.

Our approach illustrates the diversity in bill impacts over time as compared to simply assuming a single class-average customer that chooses whether or not to invest in EE or PV at a single point in time during the analysis period. By keeping the savings percentage on a per-customer basis for specific EE and PV investments static over time, we can more accurately quantify the impact of rate changes on both participant and non-participant bills based on utility cost effects of higher aggregate EE savings goals and PV market penetration.

*2.3 Altering Rate Design in Response to Expected Sales and Revenue Erosion*

The traditional electric utility business model in the United States can provide a financial incentive for the utility to increase electricity sales between rate cases, due to a reliance on volumetric energy charges to recover a sizable portion of fixed costs as well as variable costs (Moskovitz, 1989; Eto et al., 1994; Moskovitz et al., 2000). Conversely, deep savings from energy efficiency or distributed PV may result in substantial revenue erosion and under-recovery of fixed costs for the utility between rate cases (Satchwell et al., 2011; Satchwell et al., 2015a).

Utilities are expected to pursue options that mitigate this revenue erosion effect (Satchwell et al., 2015b). One ratemaking approach proposed by several utilities (NCCETC, 2016) would shift revenue collection away from volumetric energy charges to volumetric demand charges. A demand charge is a fee for electricity usage during a specified time interval (e.g., one hour) to collect utility revenues based on the volume of a customers' contribution to coincident or non-coincident peak demand (i.e., kW). Demand charges are common among large C&I customers and have been in place for many years, but are uncommon in the residential sector (Hledik, 2014). A handful of utilities have proposed various forms of residential demand charges as well as expanded use for larger C&I customers.

To explore the potential impacts of greater reliance on demand charges, we increase the share of non-fuel costs allocated to a non-coincident monthly demand charge from 0% to 50% for the residential class and from 47% to 75% for the C&I class. This change in retail rate design is also intended to be illustrative and not suggestive of what is reasonable or appropriate, particularly as concerns have been raised about the ability of residential customers to respond to demand charges and their economic efficiency.[9]

## 3. Results

### *3.1 Non-participating customers face higher bills*

Due to the rate increases when the aggressive EE and PV savings goals are met, all non-participating customers see their bills rise every year relative to what they would have been in the baseline level of achieved EE and PV savings in the BAU case.[10] Non-participants see their bills increase, relative to bills that would have occurred in the BAU scenario by 16% on a present value basis over the course of the 10-year analysis period (see Figure 5).[11]

### *3.2 Prior participants that install PV experience greater bill savings*

Prior participants experience bill savings driven by their prior EE and PV investments (see Figure 6). Those customers that already invested in energy efficiency measures see smaller bill savings (i.e., between 2 and 29% for residential and between 6 and 15% for C&I) than those customers that invested in PV systems (i.e., 95% for residential and 25% for C&I). Prior investments provide a hedge against the rate increases that occur in the AEV case. Because the EE programs elicit more modest savings, they provide a smaller hedge than PV systems that covers 100% of the residential customer's annual usage and 30% of the C&I customer's annual

[9] See, for example, Borenstein (2016).

[10] We assume for purposes of this bounded analysis that customer electricity demand is inelastic and, all else being equal, does not change in response to higher electricity rates.

[11] We observe little difference in bills across the various non-participating customer cohorts that are eligible to participate in various EE programs with common initial usage characteristics (e.g., low-income customers whose usage is 83% of the residential class average or custom rebate-eligible large C&I customers whose initial usage is 200% of the C&I class average). This is because rates are designed to be revenue neutral to the class-average customer and we scale energy and demand by the same amount, thus maintaining similar ratios relative to the customer-class average.

usage. The larger bill savings from PV investments are due to the way PV systems under a net-metering arrangement are designed to meet as much of a customer's annual energy use as possible.[12]

*3.3 Customer bill savings for new participants depend on timing of investment*

New participants make investments in EE measures through the utility program or invest in PV systems with the expectation that they will realize bill savings relative to the BAU case. However, new participants also face the retail rate increases associated with the AEV scenario. The timing of investments within the 10-year analysis period has a cumulative effect on electric utility bills. We quantify this effect by calculating the present value of different 10-year streams of annual bills (2017-2026). The basis of comparison is always the present value of the 10-year stream of a particular customer's annual bill in the BAU scenario (i.e., absent any investment in EE or PV). We then calculate the present value of different 10-year streams of annual bills in the AEV scenario based on the year when that customer chose to participate in selected utility EE programs (e.g., low-income, residential product rebate, C&I custom, or prescriptive rebate) or make a PV investment. By comparing the present value of a 10-year stream of annual bills in the BAU scenario with the present value of a 10-year stream of annual bills in the AEV scenario, we are able to not only see the impacts of the higher rates associated with the AEV scenario but also how the timing of when an EE or PV investment affects a customer's aggregate bills over time.

This comparison is made using heat maps in Figure 7 and Figure 8. The years that are color-coded in green imply that EE or PV investments undertaken by a new participant in the

[12] C&I customer PV systems cover a smaller proportion of annual energy use than residential customer PV systems because C&I customer sites are limited by the available rooftop space (Davidson et al., 2015).

year shown of the AEV scenario results in a lower present value of that customer's bill over the entire 10-year analysis period compared to the present value of customer bills over the entire 10-year analysis period in the BAU case. Alternatively, years in red show results where the 10-year present value of customer bills are higher in the AEV scenario compared to the BAU case when the investment in EE or PV is made in that year. Entries in yellow indicate that an investment in EE or PV in that given year in the AEV scenario produce a 10-year present value of bills that are comparable to the 10-year present value of bills in the BAU case.

For example, to meet the utility's PV goals in the AEV scenario, more and more residential customers must invest in a solar PV system each year. If a residential customer invests in a PV system in 2018 (assuming their usage is at the class average level), their entire load is only exposed to the higher rates in 2017. In the later years of the analysis period (2018 to 2026), this customer sees increasing rates but their utility bills will be relatively low due to the sizing of the residential PV system (again, assumed to be 100% of annual retail sales) and net-energy metering. The result is a net reduction of 80% in the 10-year present value of their utility bills. If the customer chooses to install a PV system much later in the analysis period (e.g., 2026), their load is exposed to the higher rates in the AEV scenario in all but the last year of the analysis period. In this case, the bill savings in 2026 nearly offsets the bill increases occurring in the nine previous years from the higher AEV scenario rates, although bill savings are less than if the customer had invested in the PV system earlier.

With respect to residential product-rebate and low-income EE programs, the annual energy and demand savings are too small to keep pace with the electricity rate increases, regardless of when the investment is made. The same is true for prescriptive rebate EE programs on the C&I side. Customers participating in these types of EE programs will see higher bills in the AEV scenario compared to the BAU scenario regardless of when they invested during the analysis period (early or late). In contrast, participants in the residential whole-home retrofit program that invest prior to 2023 or C&I custom-rebate program participants that invest prior to 2018 see lower aggregate bills in the AEV scenario compared to the BAU case.

### *3.4 Greater reliance on demand charges reduces bill savings for PV investments*

To mitigate the sales and revenue erosion effects from EE and PV, we model a shift in revenue collection away from volumetric energy charges to volumetric demand charges. By applying this new rate in the AEV scenario, we can assess changes in electric utility bills for different customer groups (non-participants, prior participants, and new participants) facing higher demand charges. Our goal is to better understand who is affected and how they are affected.

For non-participants that are eligible for various EE programs, the change in rate design has a very modest impact on their 10-year stream of annual bills; the impact is slightly negative in the case of C&I customers, but slightly positive in the case of residential customers due to the slightly higher proportional change in the share of revenues collected from demand charges due to our assumptions (see Figure 9). Retail rates are designed to be revenue neutral to the class-average customer in this study. Because all non-participating customers are scaled up or down from the class-average in terms of both energy and demand, the bill impact of greater reliance on demand charges in the AEV scenario is relatively minor.

Prior participants that invested in EE measures through utility programs experience little change in bill savings under a demand charge rate design. In this illustrative analysis, we assume that EE programs produce comparable energy and demand impacts on a percentage basis (see

Figure 2 and Figure 3).[13] Thus, a movement towards greater reliance on demand charges should have virtually no impact on bill savings that inure from EE investment. In contrast, prior participants with PV systems see a relatively larger change in customer bills (see Figure 10). PV systems, which typically have peak production at times different from peaks in customer load, do not reduce customer demand nearly as much as energy. This results in an erosion of bill savings of 20% for residential PV customers and 9% for C&I PV customers in the AEV scenario under a demand-charge rate design.

Demand charges also change the magnitude and timing of new EE and PV investment decisions. For new participants, the savings associated with residential product-rebate, low-income, and C&I prescriptive rebate EE programs are modest, and do not offset the the effect of rising retail rates even when cost recovery relies more heavily on demand charges (see Figure 11 and Figure 12). For residential customers participating in the whole-home retrofit program that face higher demand charges, later investments would achieve slightly lower utility bills compared to bills under the original rate design.

## 4. Conclusions and policy discussion

This research makes several important findings about the financial impact of aggressive EE and distributed PV on the electricity bills of participating and non-participating customers. Specifically, the timing of an EE or PV investment and perspective on what constitutes bill impacts matters. An *individual* customer investing in an EE or PV system that lowers their energy or peak demand, either before or during the analysis period, see lower bills than they otherwise would due to their reduced consumption level, *ceteris paribus*. However, the

[13] This is a simplifying assumption, as some EE programs produce time-variant savings (Mims et al., 2017).

*collective* effects of customers investing in EE or PV systems cause retail rates to rise for all customers in the AEV scenario relative to the BAU scenario. The increase in retail rates may partially or entirely offset the customer bill savings from EE or PV. Any analysis of customer bill impacts should take into account the feedback effects of customer investments on retail rates as it presents a more realistic perspective on the tradeoff between aggressive savings goals and increased average retail rates.

We found that increases in average retail rates had financial implications for not just non-participants, who see higher bills over the 10-year analysis period, but also for those participating customers whose investments generate modest savings of energy and demand. Customers that invest in EE measures that produce lower energy savings (e.g., residential product-rebate and low-income programs) also see higher bills over the 10-year analysis period since their savings are not large enough to offset rising rates. This finding suggests that utilities and regulators may need to reconsider EE program design and its role in a utility's portfolio. Program administrators may want to encourage customers to participate in more than one EE program or encourage more comprehensive retrofit efforts that achieve higher per-customer savings levels resulting in greater energy and bill savings.

Lower energy sales due to expanded EE and PV adoption also has implications for the recovery of utility revenue requirements, including fixed costs, between rate cases. As previously discussed, one approach to mitigating utility's revenue erosion is to recover more revenues from demand charges than volumetric charges. Our results suggest that this change to the rate structure does not tend to increase non-participant customer bills and only modestly increases EE customer bills. However, demand charges are associated with dramatic increases in customer bills for PV customers because PV systems tend to produce asynchronous reductions in energy and demand.

Ultimately, regulators and policymakers should be particularly attuned to issues of customer equity and fairness, while trying to avoid generalizations about customer bill impacts (e.g., "all participants are better off" or "all non-participants are always worse off" under a policy). Our analysis shows that the impact on customer bills depends on the type and timing of investment, the distribution of customer energy load, and cost allocation and rate design.

Finally, we note several areas of future research exploring a broader range of customer bill impacts based on altering our assumptions and applying sensitivity analysis. Further segmentation of customer cohorts by load profiles could be used to identify the structural winners or losers for various EE and PV investments. Joint investment in EE and PV could be considered. The potential for PV systems, with or without energy storage, to offset all or some portion of annual residential class load could be assessed. The effect of hourly load shapes and peaking could be modeled. Finally, assumptions about revenue requirements should be revisited, including the effect of fuel and non-fuel cost trends to influence rates as well as the value of energy savings from EE and PV investments as translated to customer bills.

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Table 1. Energy efficiency savings target for a prototypical NE utility in the business as usual and aggressive EE/PV scenarios (first year share of total utility annual retail sales without EE and PV)

| | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** |
|---|---|---|---|---|---|---|---|---|---|---|
| **BAU** | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% |
| **AEV** | 2.00% | 2.25% | 2.50% | 2.60% | 2.70% | 2.80% | 2.90% | 3.00% | 3.10% | 3.10% |

Table 2. Market penetration levels for distributed PV for a prototypical NE utility in the business as usual and aggressive EE/PV scenarios (first year share of total utility annual retail sales without EE and PV)

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|---|
| **BAU** | 0.24% | 0.30% | 0.34% | 0.35% | 0.38% | 0.40% | 0.42% | 0.44% | 0.46% | 0.47% |
| **AEV** | 0.73% | 0.90% | 1.01% | 1.06% | 1.13% | 1.19% | 1.26% | 1.31% | 1.38% | 1.40% |

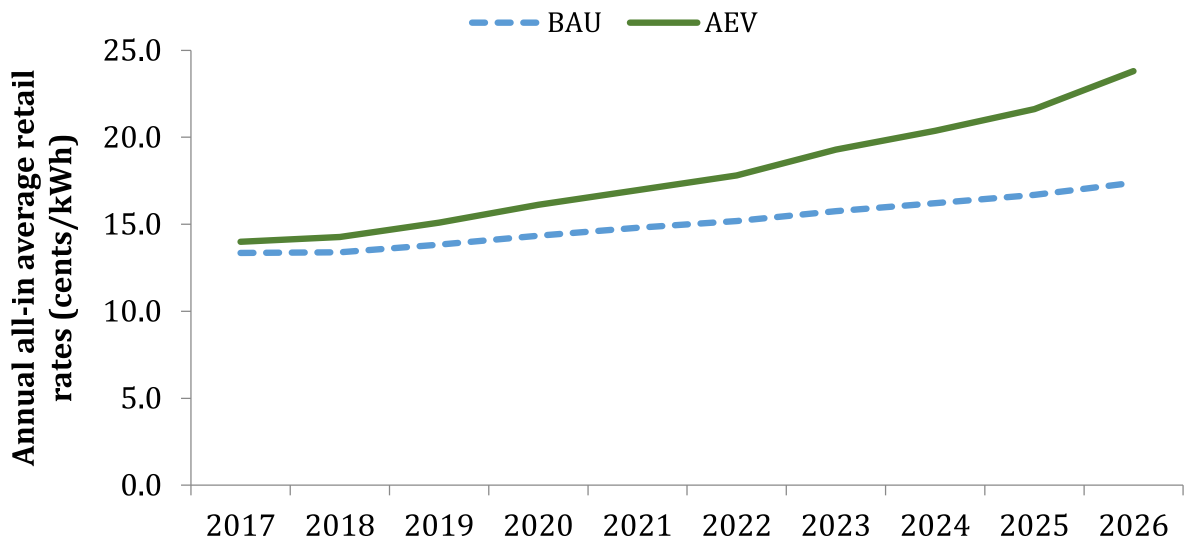


Figure 1. Annual all-in average retail rates in the BAU and AEV scenarios (cents/kWh)

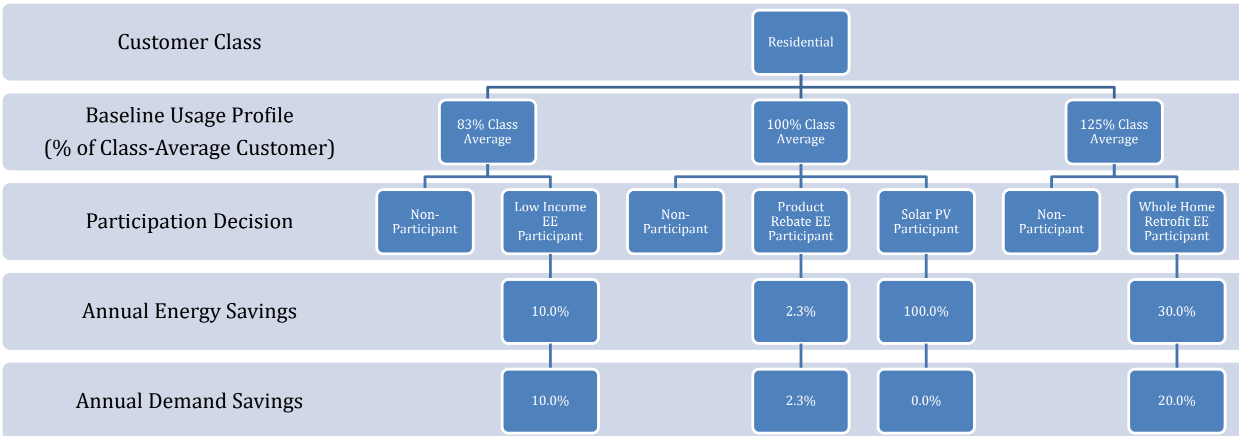


Figure 2. Participant & non-participant customer cohort characteristics: Residential class

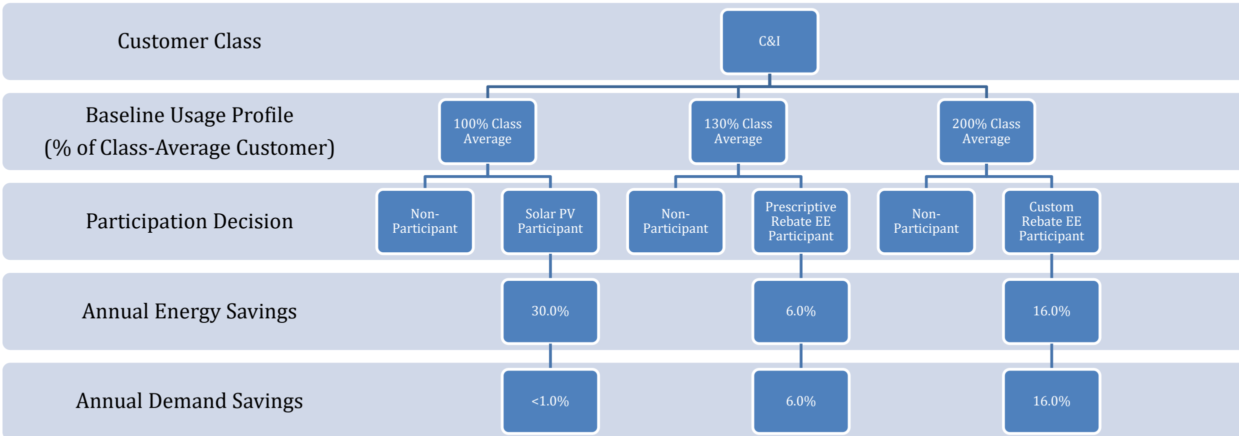


Figure 3. Participant & non-participant customer cohort characteristics: C&I class

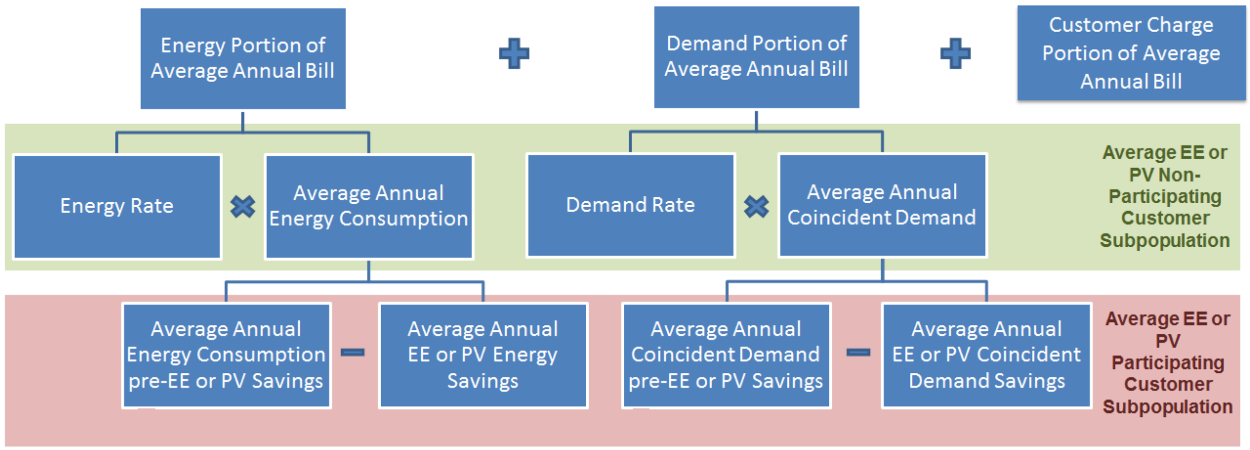


Figure 4. Bill calculation methodology for participating and non-participating customers


Figure 5. Non-participant bill impacts in AEV scenario

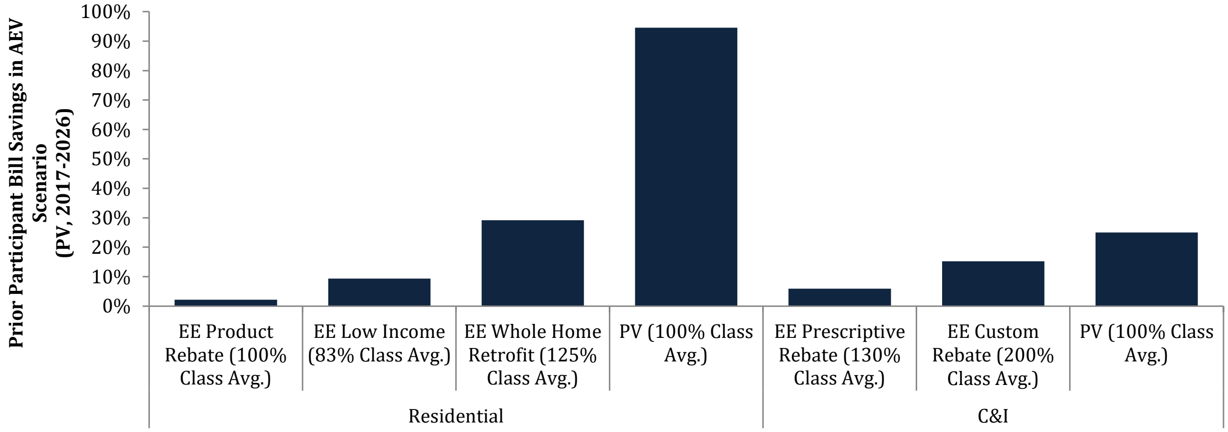


Figure 6. Prior participant bill savings in the AEV scenario

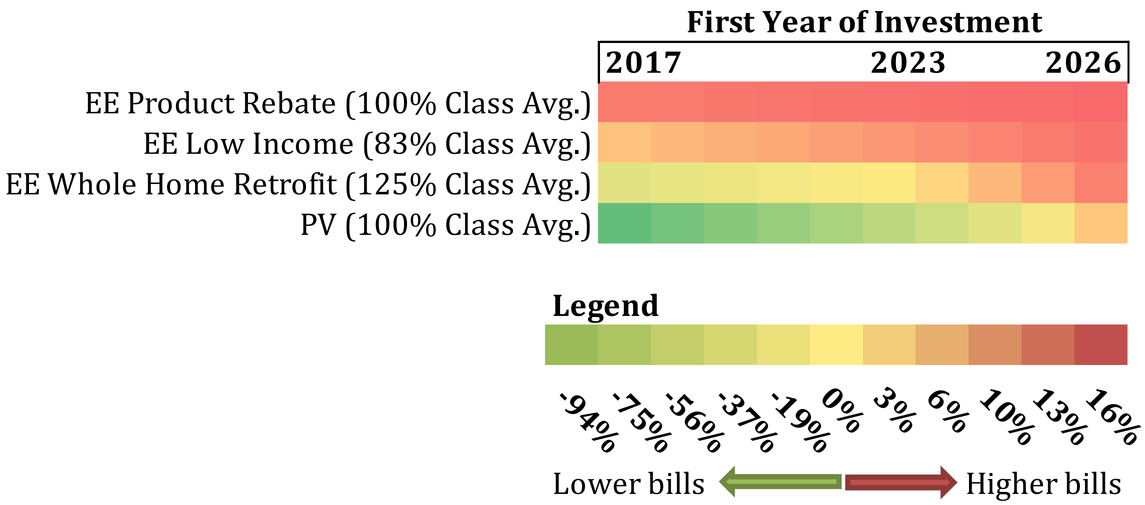


Figure 7. Residential new participant bill impacts in AEV scenario

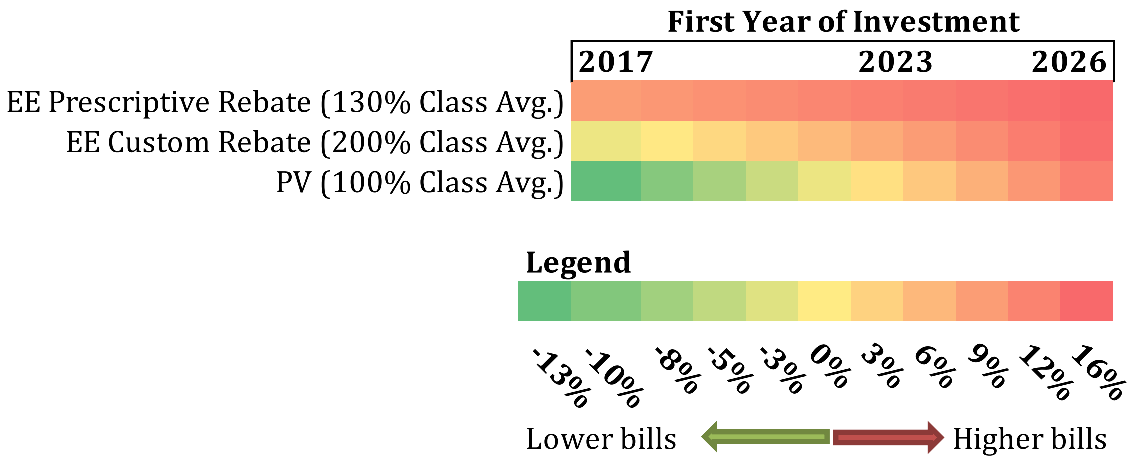


Figure 8. C&I new participant bill impacts in AEV scenario

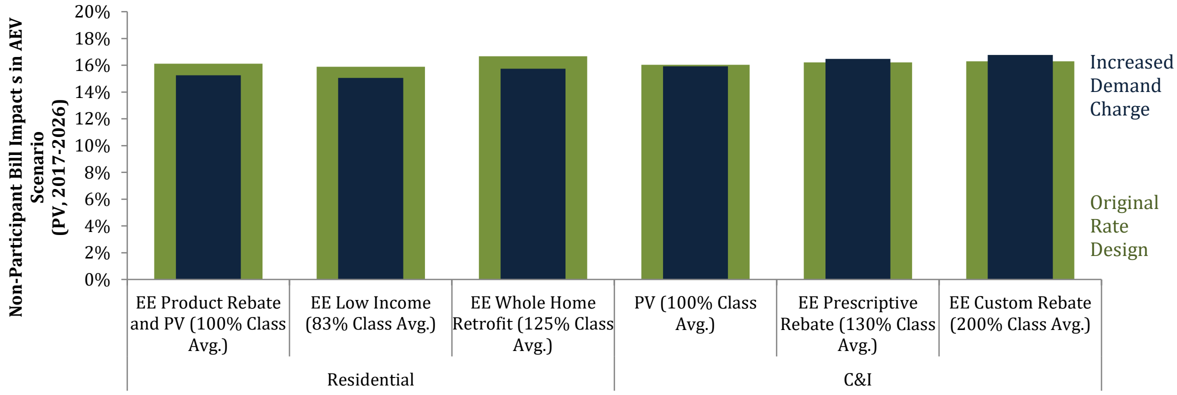


Figure 9. Non-participant bill impacts in the AEV scenario under existing and alternative rate design (increased demand charge)

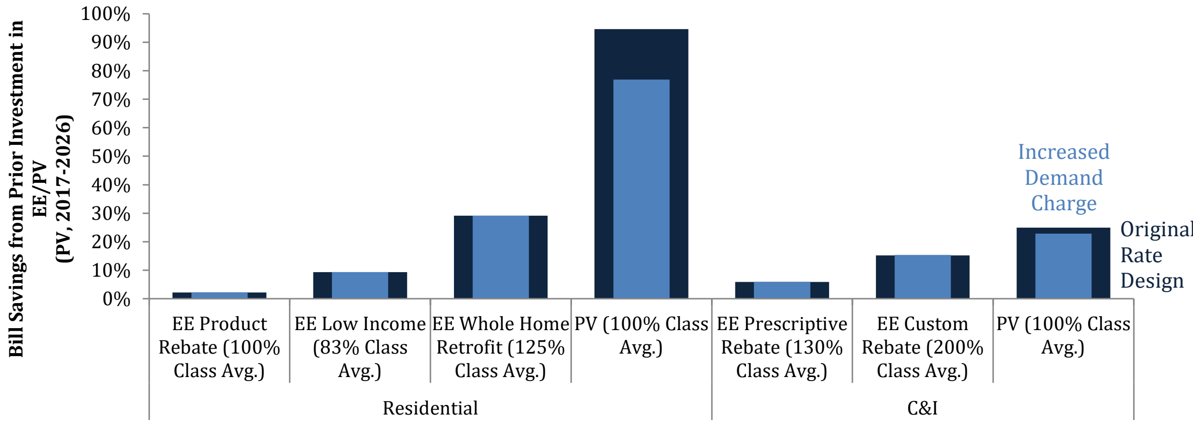


Figure 10. Prior participant bill savings in the AEV scenario under existing and alternative rate designs (increased demand charge)

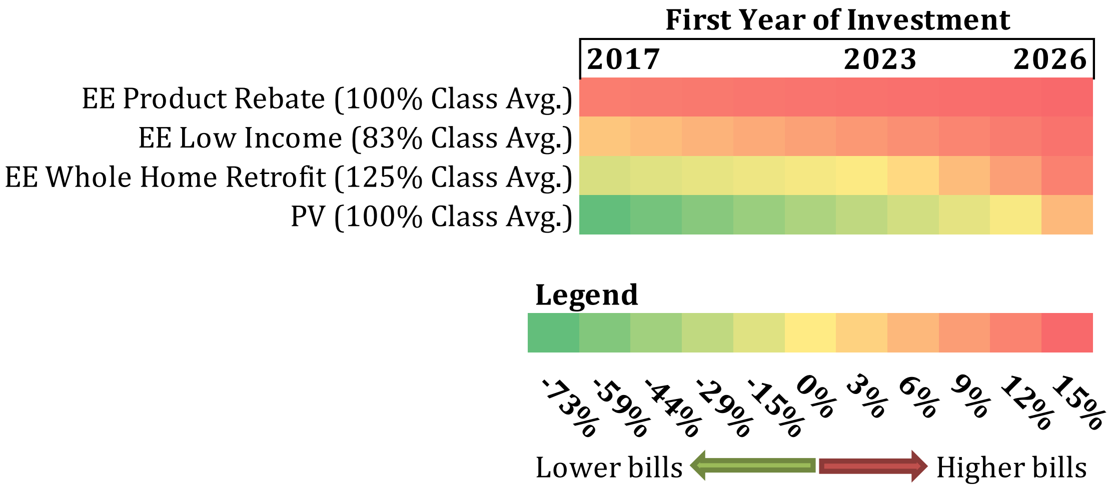


Figure 11. Bill impacts for new participants in residential EE and PV programs in the AEV scenario under alternative rate design

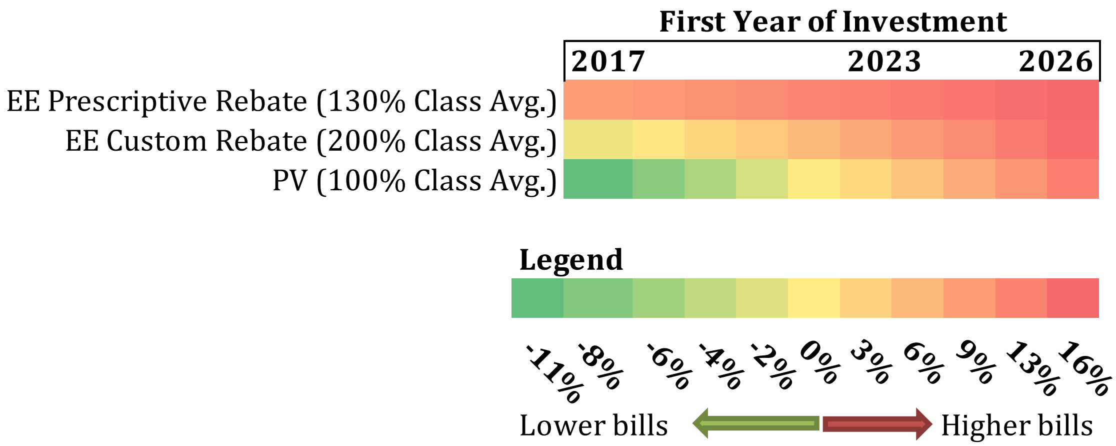


Figure 12. Bill impacts for new participants in C&I EE and PV programs under alternative rate design