Impacts of Solar Power on Electricity Rates and Bills

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ABSTRACT

The goal of this analysis is to understand the impact that solar mandates may have on electricity rates and bills of customers of distribution utilities operating in competitive markets. We examine these impacts with and without an uptick in "naturally occurring" energy-efficiency improvements. Our modeling suggests that customer classes that install solar systems fare better than customer classes that do not, because of the way that distribution costs are allocated. For example, in the scenario with high solar penetration by commercial and industrial (C&I) customers, the residential portion of distribution costs increases and experiences a tick up when the system peak shifts to later in the afternoon. In addition, customers that install solar are able to reduce bills substantially and transfer costs to non-program participants. Solar renewable energy credit costs, ancillary services, transmission costs, and social benefits charges are allocated across all sold electricity. Solar-participants avoid these charges and non-participants see increases in prices and bills as a result. Rates, consumption, and bills are also influenced by increased energy efficiency. When consumption decreases with distributed solar and energy efficiency, the utility's fixed costs must be distributed over a smaller volume of sales, reducing the bill savings enabled by improved energy efficiency. Together, these findings suggest the need for increased attention and analysis to understand the potential impact of alternative rate structures and the apportionment of fixed and volumetric costs.

Introduction

The goal of this analysis is to understand the impact solar mandates may have on electricity rates and bills of customers of distribution utilities operating in competitive markets. We developed a tool – GT-Solar – designed to model the impact that varying penetrations of solar electricity has on revenue requirements, as well as impacts on household, commercial, and industrial consumer electricity bills. This tool compiles data from electricity supply markets, distribution costs, customer hourly demand curves, and solar generation profiles in order to compile revenue requirements. It then allocates revenue requirements across different rate classes, simulating a typical set of customer rate structures. This model allows us to demonstrate impacts of solar electricity generation requirements under a wide range of scenarios, including one where the magnitude of "naturally occurring" energy efficiency increases significantly.

Motivation for Research and Analysis Objectives

Renewable portfolio standards and corresponding solar "carve-outs", where a fraction of the renewable portfolio standard requirement must come from solar, are now commonplace. This presents unique challenges for utilities, which must maintain service and reliability, meet revenue requirements, and equitably charge customers while incorporating solar and purchasing solar renewable energy certificates (SRECs) to comply with the renewable portfolio standard. Distributed solar, and in particular, net energy metering (NEM) – where customers pay only for net energy use – can influence traditional cost sharing and pricing structures. Because many costs associated with electricity service are fixed costs, capacity costs, ancillary services, programmatic costs, or are a function of peak demand, these installations may change the cost structures for electric utilities and their customers. Based on assumptions of a typical distribution utility, the purpose of this analysis is to utilize GT-Solar to help anticipate these revenue, rate, and bill impacts to provide a clear understanding of the impacts of solar penetration on the electricity system. How does NEM affect customer bills and how does this affect the distribution of system costs across customer classes? In addition, we consider how large-scale NEM may interact with energy-efficiency (EE) investments by considering their impacts in a scenario where “naturally occurring” energy-efficiency improvements eliminate load growth. We argue that the rate escalation resulting from NEM programs make energy-efficiency investments more attractive since NEM increases rates due to fewer customers over whom to spread fixed costs. Therefore, the two trajectories—greater solar penetration and energy efficiency—are considered in tandem.

The magnitude of the costs and benefits of distributed photovoltaic installations vary according to the level of penetration, the local grid characteristics, and the coincidence of the solar electric production with the coincident and non-coincident peak demands in the utility’s region. Assessments of costs and benefits have varied widely and are largely case specific (Bird et al., 2013). Previous studies have noted that utility lost revenues are a potentially significant cost, particularly if there are no mechanisms in place to adjust for lost sales (Council & Energy, 2013). Because of fixed costs billed as throughput costs, NEM customers are able to avoid many of the fixed costs associated their service causing others to pay for these costs. Between rate cases, NEM can have sales impacts that can exceed those previously forecasted and cause rates to rise to account for lost revenue. Raising rates further incentivize customers to participate in NEM and to invest in energy efficiency, a cycle that has been coined the “death spiral” (Kind, 2013, Cardwell, 2013). As a result, utilities may be forced to explore different business models and rate options (Brown, et al., 2015, Costello & Hemphill, 2014).

Rate and bill impacts are critical for assessing the distributional effects of a solar mandate. Rate impacts provide an indication of the extent to which overall electricity rates might increase. Bill impacts highlight differences between NEM participants and nonparticipants. Experience suggests that bills may be reduced for NEM customers but will increase for nonparticipants (Synapse Energy Report 2014). Because NEM customers receive retail rates for energy they provide to the grid or use to reduce their own demand they may not be adequately paying for grid services such as transmission, distribution, and other ancillary services that they still consume. In this case, the non-participants in NEM subsidize the NEM participants’ use of grid services.[1] This result has equity consideration as well since residential NEM participants have incomes well above average utility customers (CPUC, 2013).

In addition to these equity concerns, there is also concern that due to the way rates are constructed, solar penetration will impact the distribution of costs across rate classes, leading certain rate classes to subsidize others. There are substantial differences between residential and non-residential rate structures and rates themselves. Non-residential rates include lower energy charges but contain additional demand based tariffs. In California, analysis found that because NEM systems reduced net energy consumption by a greater percentage than they reduced peak demand, residential customers saw greater bill savings than non-residential customers (CPUC, 2013). In addition, different classes of customers have different hourly load profiles, which can

[1] It should be noted that solar NEM customers are also providing relatively valuable electricity to the grid since solar generators produce electricity when wholesale electricity prices are relatively high suggesting this is less of a problem than if NEM customers produced electricity at night.

have consequences for rates and bills as the electricity system's coincident peak shifts with solar penetration. In this analysis the rate structures are disaggregated and several installation scenarios are investigated to provide insight regarding rate class cross subsidization.

Finally, there are issues with the coverage of public purpose charges. The purpose of these charges vary from state to state but typically fund energy efficiency within the state, universal access to electricity, consumer education programs, and a host of other policy goals. NEM customers avoid some portion of these charges by reducing purchased electricity. These avoided charges are then primarily collected only from non-participants and public programs may become underfunded. For example, California estimated NEM customers would avoid $142 million in public purpose charges which accounted for 6.3% of the total estimated public purpose funding (CPUC, 2013).

Methodology

The prototypical utility modeled by GT-Solar divides its power business into an electricity supply system (that buys and sells power and manages high-voltage transmission lines along with associated transformers) and an electricity delivery system (that manages distribution substations, transformers, poles, and service lines that bring the electricity to meters).

The utility does business with three classes of customers: residential, small commercial, and large commercial and industrial. The vast majority of customers are residential, and they account for almost a third of electricity consumption. Small business accounts for somewhat more of the electric consumption, and industrial customers account for somewhat less.

For most residential customers, the amount of electricity consumed between meter reading dates is the basis of their bills. For small business and C&I customers, the amount of capacity consumed by the customer is also measured for each billing cycle. This is done with time-of-day meters or demand recording meters.

Non-residential rates are based on usage characteristics such as the level of peak demand, whether electricity is used for space heating, and whether it is received at primary or secondary voltage levels. The customers served under small business rate are the small and medium commercial and industrial customers whose peak demand does not exceed 150 kW in any given month. Customers served under the C&I rate are the larger non-residential customers served at either primary or secondary distribution voltages.

Customer Load Shape Profiles

Data for aggregate customer load profiles were obtained using 4 years of historical data from 2011 to 2014 from a northeastern utility. A total of nine load profiles were developed from these data. Each of these nine profiles contains 24 representative hours that we assume are identical for each day in a month. A separate load profile was calculated for each of the three rate classes: residential, small business, and C&I. Within each rate class a load profile was created for the average weekday (Monday through Friday), weekend, and system peak day.

Hourly Solar Generation of Participants

The solar generation profiles were developed based on data from solar customers from 2010 to 2013 and includes both the system size and the kWh generated by hour. The generation is divided by system size to calculate the capacity factor for each hour of each month for the entire year. Independent solar profiles are created for each of the rate classes to account for different optimizations (i.e., to maximize peak simultaneity, or due to roof characteristics). In addition to the average solar profile, a peak solar profile was created to represent an average of the peak solar day in each month for each of the four years. We compared the monthly average precipitation and temperature over our 4-year solar production sample period to the National Oceanic Atmospheric Administration's “climate normals” and find no statistical difference between those normals and the average temperature and precipitation.

Supply Cost Data

In order to properly calculate how the total electricity bills will change in the utility’s service territory in response to increased solar penetration, we modeled how increased solar will affect the region’s wholesale market prices. We focus primarily on changes to the electricity markets through both reduced demand (from NEM customers) and increased supply from grid connected solar installations. We estimate a market supply curve using historical market data. Due to the size of the wholesale market relative to the utility’s electricity demand and our studied solar requirements, there are limited price changes in this market in response to increased solar penetration.

Distribution Rate Design

We choose to model a rate design that is relatively common across many electric distribution utilities in the United States and choose the monetary value of charges to be commensurate with some observed charges. In our model, customers in each rate class are charged a fixed fee for service. These service charges recover a portion of the costs associated with reading the customer’s meter, billing and other fixed costs and for having the service available regardless of the customer’s level of use.

In addition to the fixed service charge, residential customers are billed for distribution services using a fixed price per kWh to recover costs associated with distributing electricity to the customer’s premises. The charges have two tiers with an increasing block rate that is lower for the first 600 kWh than for subsequent consumption. It is also seasonal, with higher rates in the summer than the winter. Residential customers are also charged on a volumetric (per kWh) basis for a variety of miscellaneous charges valued at about 2.6¢/kWh.

As is true of all rate classes, non-residential customers have a fixed service charge with a few optional charges depending on the nature of their services. They are subject to an annual demand charge that is assessed on a monthly basis and is determined by the highest kW demand registered in any 30-minute cycle during the billing period. A summer demand charge, determined by the highest on-peak kW demand helps the utility recover the higher costs of maintaining its electric distribution system during peak summer months.

The NEM Program

NEM enables retail customers who generate electricity through their own renewable systems to receive full retail price for each kWh of electricity their system produces. To be eligible for net metering, customers must have an interconnection agreement in place, which confirms that the generating capacity of their system does not exceed the customer’s annual electric needs. For those participating in net metering, full retail credits are only given up to

100% of electricity usage over the course of the year. In practice, using net metering allows the meter to spin forward when electricity flows from the grid into the home or business and in reverse when electricity flows from the solar system to the grid. When production exceeds usage the meter spins backwards and customers are provided with credits. These credits are “netted” and then paid back on an annual basis.

Solar Penetration Scenarios

In addition to comparing future bills and rates to those in 2015, we also compare scenarios against a projection of the current NEM Program. This projection assumes that grid-connected solar accounts for 33% of new additions annually, residential solar accounts for 50% of new additions of net metered solar, and small business solar accounts for 20% of new additions of net metered solar in C&I.

The utility we examined is located in a state that has passed one of the most aggressive solar requirements in the country, mandating that 4.1% of electricity sold in 2028 (with interim requirements) must come from solar. We also model a high solar penetration level calculated as tripling the current pace of solar installations, reaching 12.3% of electricity sold in 2028 with the same allocation of solar installations as in the current case. Finally, we evaluate four side cases based on this High Case, which include the following:

- High Case with High Residential Participation
    - Triple current RPS requirement (to reach 12.3% in 2028) with a continued growth in effective RPS requirement of approximately 0.3 percentage points in 2029 and 2030
    - Grid-connected solar accounts for 33% of new additions annually
    - Residential solar accounts for 80% of new additions of net metered solar
    - Small business solar accounts for 20% of new additions of net metered solar in C&I
- High Case with a High Proportion of Grid-Connected Solar
    - Triple current RPS requirement (to reach 12.3% in 2028) with a continued growth in RPS requirement of approximately 0.3 percentage points in 2029 and 2030
    - Grid-connected solar accounts for 50% of new additions annually
    - Residential solar accounts for 50% of new additions of net metered solar
    - Small business solar accounts for 20% of new additions of net metered solar in C&I
- High Case with Both of the Above
    - Triple current RPS requirement (to reach 12.3% in 2028) with a continued growth in RPS requirement of approximately 0.3 percentage points in 2029 and 2030
    - Grid-connected solar accounts for 50% of new additions annually
    - Residential solar accounts for 80% of new additions of net metered solar
    - Small business solar accounts for 20% of new additions of net metered solar in C&I
- High Case with More Naturally Occurring Energy Efficiency
    - The demand for electricity is assumed to stay flat rather than growing at an average annual growth rate of 0.25% used in the other scenarios

Results

We examine the impacts of high solar penetration across the alternative scenarios, over time, across customer classes, and between solar participants and non-participants. Impacts include annual SREC costs, electricity rates (supply and distribution), electricity bills, time series of bills with shifting peak hours, and bills for solar participants and non-participants.[2]

Rate Impacts by Customer Class

A comparison of the Base Case and the High Solar scenarios leads to several findings about the rate impacts of significant solar penetration (Figure 1). When measuring the impacts as percent change in rates in 2030 relative to 2015, it is important to note that on average, supply rates are higher than distribution rates (by a ratio of 4-to-1, for instance, for residential customers). Also, both supply and distribution rates are higher in the summer than in the winter.

In all scenarios, supply rates are forecast to increase between 2015 and 2030. Supply rates increase even more in the High Cases due to the underlying cost increase of about 5-10%, in response to the increase of SRECs and ancillary services, which are paid for by all customers, and the greater reduction in sales, which spreads the SREC costs over a smaller base. The SREC increase accounts for about 1¢/kWh of the increase over the Base Case in 2030; however, this estimate is an outcome of input price assumptions for SRECS. No increase in ancillary services is assumed in the Base Case but an increase of 1% of the value of sales is assumed in the High Case, which is a doubling of these costs above the Base Case. Supply rates rise slightly more in the winter than in the summer and they rise more in off-peak than in on-peak periods. This is because the extra costs associated with SRECs and ancillary services are spread over a smaller volume of sales in the winter and off-peak periods.

Impacts on distribution rates are more variable across the scenarios and customer classes. In the Base Case, distribution rates for residential and C&I customers are forecast to decrease between 2015 and 2030, while they are forecast to increase for small business customers due to higher demand charges. For all three cases, Base Case increases/decreases in distribution rates over the 15-year period are less than 1.8% from rates in 2015.

Distribution rates change more significantly when solar penetration is tripled. With High Solar penetration, distribution rates are higher in the High Solar scenario than in the Base Case for the residential and small business customers, but distribution rates decline for C&I customers. The increase for residential customers (as much as 27%) is due to changes in the peaking hour of demand due to solar production and a subsequent change in how distribution costs are allocated. Demand seen by the grid operator shifts as a result of solar production. Because of this shift, residential customers change from being responsible for 41% to 52% of total system distribution costs, driving their costs up substantially.

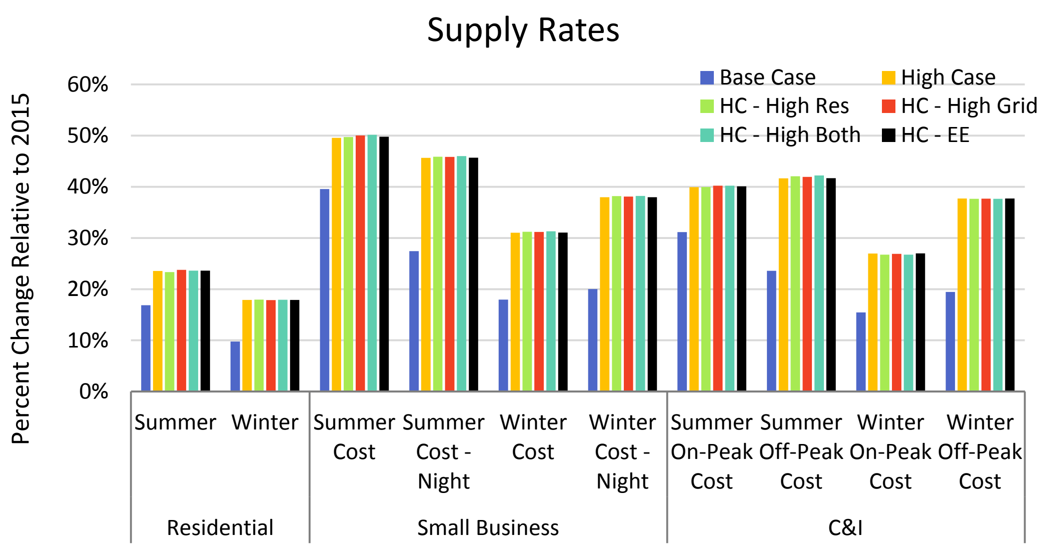
Recall that in the High Case, the majority of solar capacity is in the C&I sector, with only 20% of the installations in residences. Yet distribution rates for residential and small business customers generally increase more between 2015 and 2030 in the High Case compared with the Base Case (e.g., an increase of approximately 0.5¢/kWh for households, resulting in rate hikes of 11-12% above 2015 rates by 2030). Similarly, demand charges for small businesses increase by more than 5% in the High Case compared to 2015 rates. In contrast, demand charges for C&I customers decrease in the High Case by more than 5% compared with the 2015 rates. This is

[2] All results are presented in real dollars with a base year of 2010.

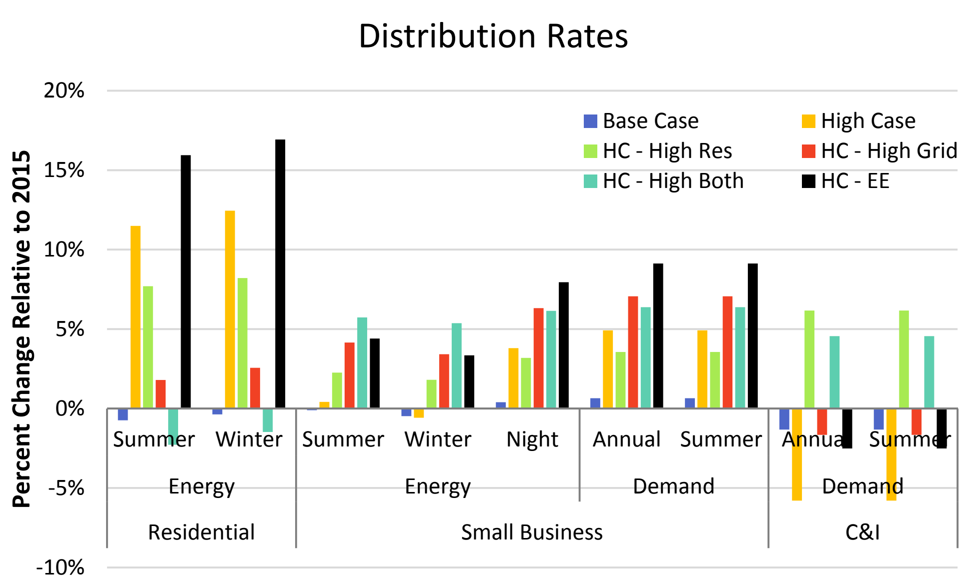
largely because the C&I class is responsible for a smaller portion of the system coincident peak in the High Case.

In sum, rate impacts are highly dependent on the level of participation of different customer classes in NEM programs.

Figure 1. Changes in Supply and Distribution Rates Across Solar Scenarios: 2015 to 2030*



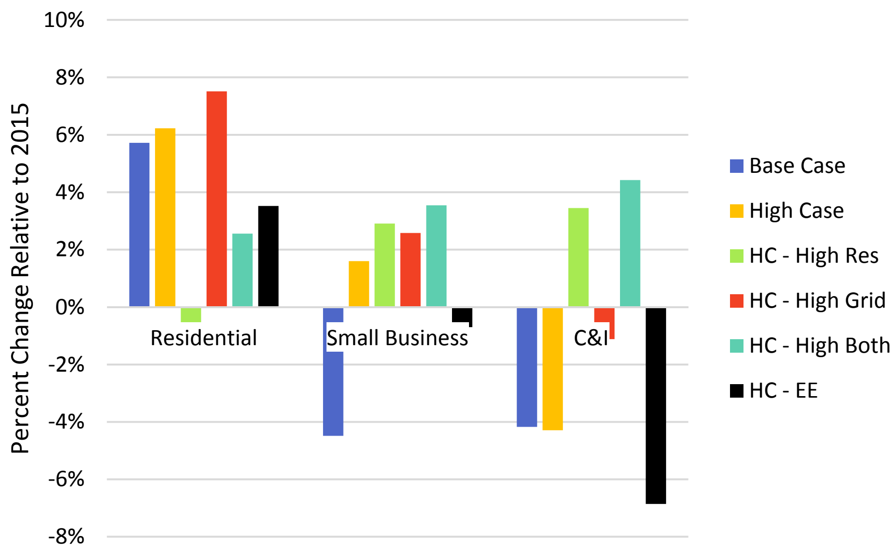
*Supply rates are measured in $2015/kWh and distribution rates are measured in $2015/kWh for energy and $2015/KW for demand.



Bill Impacts by Customer Class

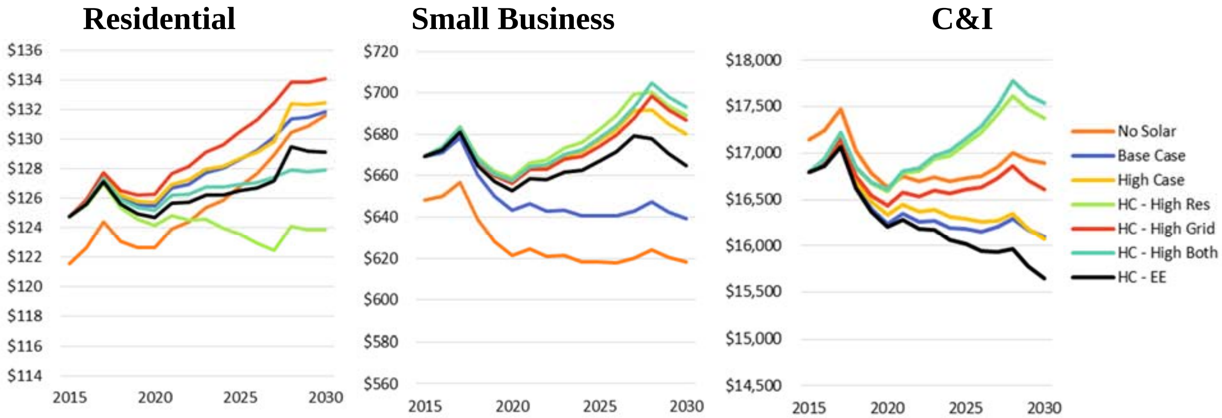
Residential electricity bills are projected to increase by nearly 6% in real terms from 2015 to 2030, assuming that the solar installation patterns across customer classes and between grid- and distributed solar remain the same as in recent years. Small business and C&I bills, in contrast, are projected to decrease. These impacts change in magnitude and direction across the levels of solar market penetration (Figure 2).

Figure 2. Changes in Electricity Bills: 2015 to 2030



The forecast shows bill increases to be highest for residential customers in the High Case, when supply costs also rise the most. In addition, residential customers account for an increasing portion of the utility system's coincident peak, which shifts by an hour to later in the afternoon, increasing the costs allocated to the residential rate class. Small business customers would also experience increased bills in the High Case (but not in the Base Case). As with the residential class, the utility's coincident system peak increases the portion of the peak attributable to small businesses. C&I customers experience a decrease in bills in four of the six scenarios. Because the C&I customers account for the largest portion of NEM generation in the Base and High Cases, their bills see the largest decreases. In addition, the peak in their overall hourly consumption shifts away from the system peak. The impacts of these shifting peaks are shown in Figure 3.

Figure 3. Average Monthly Bills Over Time (in $2015/Customer)



The impacts of solar installation on bills is best illustrated by looking at the series of High Cases that change the installation patterns of solar panels. Our five High Case scenarios visualize additional underlying causes of subsidies that could occur across the three classes of customers, under alternative allocation assumptions: (1) when solar expansion is greatest in the residential sector, shifting away from C&I (HC-High Res), (2) when grid-connected solar installations grow to nearly 50% of all solar penetration in 2030 (HC-High Grid), (3) when both of these allocations occur simultaneously (HC-Both), and (4) when energy-efficiency improvements eliminate load growth (HC-EE).

Electricity bills for all residential customers in 2030 would rise the most in the high scenario that has the lowest residential participation in the solar program (that is, HC-High Grid). Residential electricity bills would decrease by about 1% in the case with the greatest residential participation (that is, HC-High Res). Electricity rates, consumption, and bills all depend on the relative rate-class participation of residential households in the NEM program. Residential rates, consumption, and bills are also influenced by increased energy efficiency (HC-EE). While their consumption decreases, the utility's fixed costs (including increased SRECs and ancillary services) must be distributed over a smaller volume of sales, increasing rates and reducing the bill savings enabled by improved energy efficiency.

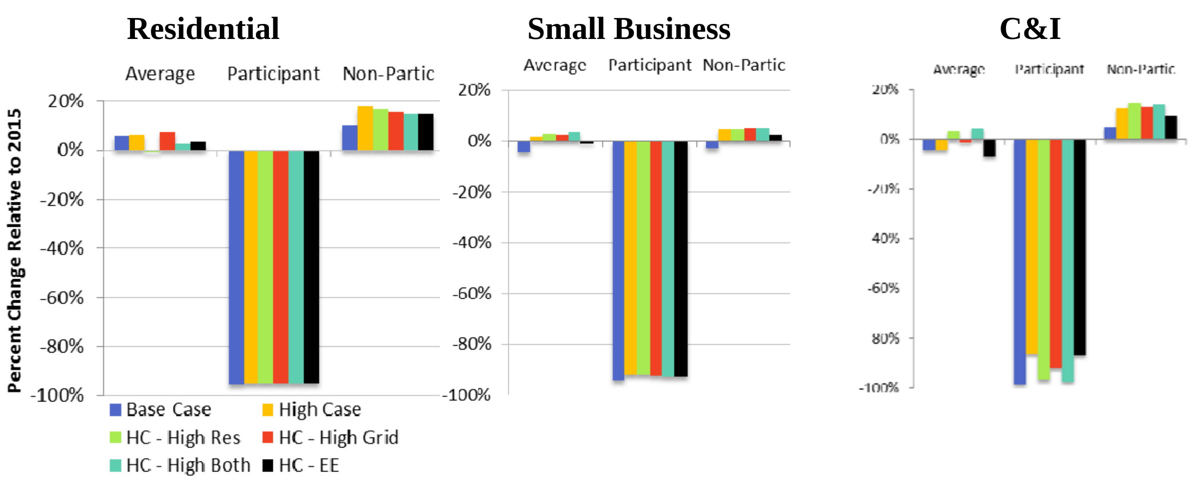
Electricity bills for all small businesses rise by 2 to 4% across all of the High Cases – as DG transitions to grid-connected solar, and as low residential participation transitions to high residential participation. Both of these shifts would reduce the solar capacity of small business customers. On the other hand, bills for small businesses would decrease slightly with increased energy efficiency (HC-EE): the savings from consuming less electricity would be slightly greater than the increased cost from higher rates.

The average monthly bill of all C&I customers are forecast to increase in only two of the five High Cases – the cases with high residential participation. In these scenarios, bills could increase by 3 to 5%, reflecting the fact that C&I customers have lower NEM participation and therefore greater requirements for purchased power relative to the High Case. In contrast, when residential installations do not dominate, C&I customers benefit. In particular, they see the largest bill declines in the High Case when C&I customers have strong NEM participation and when there are significant energy-efficiency improvements.

Bill Impacts Across Solar Participants and Nonparticipants

Average bills for residential and small business customers generally increase between 2015 and 2030 across the High scenarios, compared to the Base Case (Figure 4).

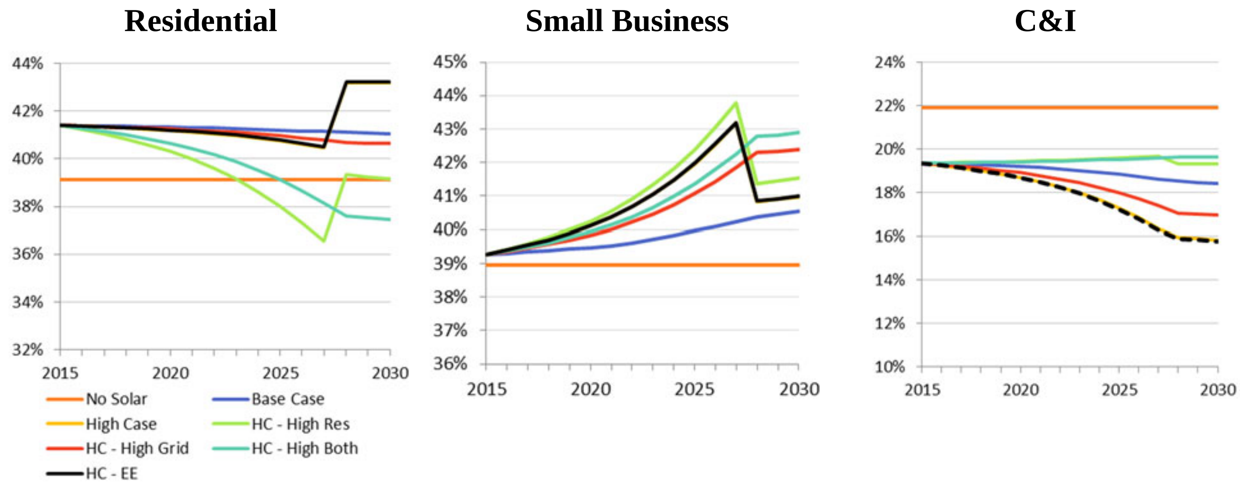
Figure 4. Percent Change in Electricity Bills Across Participants and Non-Participants: 2015-2030



As anticipated, the electricity bills of participants drop significantly – by approximately 90%, while the bills of non-participants increase from 5 to nearly 20%. Non-participant bills across customer classes increase least among the High Cases when there is an increased implementation of energy efficiency (HC-EE). Non-participant household bills increase most when C&I participants dominate the NEM program, and similarly non-participant C&I bills increase most when residential participants dominate the NEM program.

Non-participant bills in the small business customer class depend on class responsibility for the system's coincident peak (Figure 5). GT-Solar defines the system coincident peak hour as the hour with the largest peak demand among the 12 monthly peak days in each year. In 2015, residential customers were responsible for 41 percent of the system coincident peak, which occurred in July at 4 pm. Small businesses were responsible for 39 percent and C&I customers accounted for the remainder (19 percent).

Figure 5. Percent of Utility System's Coincident Peak Attributable to Each Customer Class: 2015-2030



The significant increases in solar power represented by the High Case moves the system coincident peak from 4 to 5 pm between 2027 and 2028, and from 5 to 6 pm between 2028 and 2029. (Note: the High Case is hidden by the HC-EE Case, which tracks the same.) As a result, the residential customers become responsible for 46 percent of total system distribution costs, driving costs up substantially for households. In contrast, small businesses drop to 37 percent and C&I customers account for the remaining 16 percent of the system coincident peak.

In the HC-High Both scenario (that is, with high residential participation and high grid-connected solar), the residential class has the lowest responsibility for the coincident peak, while the small business class has increased responsibility, and the C&I class remains flat at about 20%. Thus, the residential class benefits most, once again, when it is the principal recipient of solar panels.

Conclusions

Many of our findings are subject to significant caveats: it is impossible to project prices for solar renewable energy certificates, solar photovoltaic systems, and natural gas into the future with any degree of certainty, and it is difficult to estimate the increased level of investment in energy efficiency that might occur as a result of increased electricity rates. With these caveats, we offer the following conclusions from our analysis of different magnitudes of solar penetration and different patterns of solar installation across customer classes and between distributed and grid-connected solar.

First, the level of solar penetration matters. Electricity bills in the high solar penetration cases are higher for all customer classes due to additional supply costs associated with the purchase of extra ancillary services and SRECs.

Second, increasing the solar requirement also affects the allocation of distribution costs across customer classes because load profiles shift when solar penetration is high. For example, tripling the market penetration of solar systems (as in the High Case), increases the costs allocated to the residential rate class because residential customers would account for an increasing portion of the utility system's coincident peak.

Third, solar installation patterns matter, and they interact with overall levels of solar penetration. For example, residential bills in the High Case-High Res (with a large proportion of solar residential customers), benefit both from lower purchased electricity and a lower portion of distribution costs due to reductions during the coincident peaks. This is coupled with an increase in bills for the other customer classes. This logic carries through to small business and C&I customers. Installing a larger amount of solar in a particular rate class generally offsets increases in the electricity bills of that rate class.

Fourth, large distributional changes occur within rate classes due primarily to the cross-subsidization of fixed costs. Customers that install solar systems fare better than customers that do not install solar systems, because they are able to reduce their purchased electricity substantially, thereby transferring costs to non-program participants. SREC costs, ancillary services, transmission costs, and social benefits charges are allocated across all sold electricity. Solar participants avoid these charges and non-participants see increases in prices and bills as a result.

Fifth, there are distributional effects at the individual customer level, particularly for small business and C&I customers that have demand charges. Because customer demand profiles change, electricity bills for individual customers can change substantially, shifting their peak hours of demand and levels of on-peak consumption, thereby impacting individual demand charges and bills.

Finally, increasing the efficiency of electricity consumption can offset the bill increases that non-participants (and solar participants) might otherwise experience as the result of higher electricity rates. Whether or not the dampening impact of efficiency on bills can offset the price escalation from higher rates depends upon many factors including: (1) the magnitude of the end-use efficiency improvement, (2) the hourly load shape of the demand reductions, (3) the level of solar penetration, and (4) the impact of solar generation and efficiency on the utility system's coincident peak. For participants, the scale of the solar system relative to usage also determines the impact of energy efficiency on electricity bills. Future research is needed to explain more fully this array of factors impacting the role of energy efficiency in a future of high solar penetration.

Together, these findings suggest the need for increased attention and analysis to better understand the potential impacts of alternative rate structures and apportionment of fixed and volumetric costs. It is becoming clear that current pricing policies are imperfect reflections of economic pricing principles, such as aligning charges with cost causation.[3] Utilities across the country are considering a variety of alternative pricing schemes to enable them to adequately recover fixed costs under increasing amounts of self-generation and energy efficiency (Lively and Cifuentes, 2014).

Alternatives include the use of minimum bills, straight fixed variable rates with dynamic pricing, time of use pricing, demand charges for residential customers, various net metering rate structures, and differential charges for distributed generation participants and non-participants. Pricing options are hampered in the short run by the limited penetration of smart metering that is required to measure maximum demand and to move to time-of-use pricing to better reflect long-run marginal costs (U.S. Energy Information Administration, 2014).[4] As distributed resources

[3] https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/

[4] In 2014, there were 52 million smart meters installed in the residential sector (U.S. Energy Information Administration, 2014). Smart meters range from basic hourly interval meters to real-time meters with built-in two-way communication.

become more prevalent, the pros and cons of alternative pricing strategies require further analysis. In anticipation of universal smart meters, the next generation of pricing options also needs to be considered.

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