



Peak shifting and cross-class subsidization: The impacts of solar PV on changes in electricity costs[☆]



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ABSTRACT

The expansion of distributed solar necessitates additional research into the impacts on both utilities and their customers. In this paper we use New Jersey solar data, PJM market data, and demand profiles from a PJM utility to investigate rate and bill impacts of large-scale solar penetration. In addition to the subsidization of solar adopters by non-participants, we highlight the channels through which cross-subsidization of rate classes can arise in practice. The results of our study indicate that the fear of a utility “death spiral” may be exaggerated. Significant solar can be incorporated with only a 2% increase in non-participant bills. At high levels of penetration, distributed solar has the potential to alter the system peak hour which affects the allocation of costs across rate-classes. As the peak hour shifts to the evening when solar production diminishes, residential customers face higher distribution costs. Policy makers and utilities need to be aware of these challenges in designing the next generation of rates that are better aligned with cost causality.

1. Introduction

With more than 25 GW of installed cumulative capacity through 2015 and 16 GW expected to be installed in 2016, solar energy has been a rapidly growing source of electricity in the United States over the last decade.¹ In recent years, the proliferation of solar rooftop systems has taken off at the residential and commercial level, and utility-scale solar installations have grown as well. Recent evidence suggests residential photovoltaic (PV) systems were the fastest growing sector in the U.S. solar market in 2015 ([Solar Energy Industries Association, 2016](#)). This trend in residential PV installations has been accelerated by the combination of declining manufacturing costs for PV modules and attractive local, state, and federal financial incentives. As a consequence, several states in the U.S., particularly California, New Jersey, Colorado, and Texas, have seen substantial deployment of solar resources in recent years ([Rai and McAndrews, 2012](#)). However, even current levels of deployment represent only about 1% of electricity generation in 2015 (EIA, 2016) and is a small portion of the market potential in the U.S. ([Paidipati et al., 2008](#)), indicating the possibility of future market expansion. This expansion of distributed solar changes

the traditional utility-customer relationship and demands additional research into how solar growth will affect both sets of stakeholders.

Previous studies have noted that the magnitude of utility lost revenues due to eroding sales is non-trivial, especially if there are no mechanisms in place to adjust for lost sales. To compensate for lost sales, utilities may be forced to raise rates, which further incentivizes customers to invest in energy efficiency and distributed generation, leading to an additional decline in revenues for the utility. This cycle has been coined the “death spiral” ([Cardwell, 2013](#); [Kind, 2013](#)); as a result, utilities may be forced to explore different business models and rate options ([Brown et al., 2015](#); [Costello and Hemphill, 2014](#)). When utilities raise retail prices for all customers, this rate adjustment process leads to an implicit subsidization because net metered customers are, in effect, permitted to sell excess generation back to the utility at the retail rate ([Borlick and Wood, 2014](#); [Brown and Lund, 2013](#); [Rose et al., 2008](#)). Prior literature establishes that bills will be reduced for distributed solar adopters but will increase for nonparticipants ([Eid et al., 2014](#)). The implicit subsidization between non-adopters and adopters of solar technology may have important distributional effects within a given rate-class because residential solar adopters are typically households with higher incomes ([California Public](#)

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¹ <http://www.seia.org/news/us-solar-market-set-grow-119-2016-installations-reach-16-gw>

Utilities Commission, 2013).² While other studies have focused on the subsidy between net energy metering (NEM) participants and non-participants (henceforth simply participants and non-participants), we examine how solar penetration can also impact the distribution of costs across rate classes, causing one or more rate classes to subsidize others.

The purpose of this paper is to investigate and highlight the channels through which subsidization across and within rate classes can arise in practice. This effect has not been widely studied in the literature because most research focuses only on impacts to residential consumers. Importantly, there are substantial differences between residential and non-residential rates and rate structures. By simulating the effects of combining a solar renewable portfolio standard (RPS) carve-out with a utility-level NEM program, we are able to investigate and detail the consequences of different solar installation patterns on the rates and bills of customers of electric utilities operating in wholesale markets. Our simulation combines data from the PJM wholesale market, solar production data from installations in New Jersey, and publicly available demand profiles from a northeastern U.S. electric utility. Our methodology explicitly focuses on two metrics that are likely impacted by solar penetration and quantifies the extent of cross-subsidization between rate-classes: (1) retail electricity rates (cost per unit) and (2) electricity bills (total monthly cost). On one hand, rate impacts provide an indication of the extent to which overall electricity rates might increase. On the other hand, bill changes reflect the *ceteris paribus* effect of solar installations between NEM participants and non-participants.

Our analysis improves on the existing literature in three important dimensions. First, nearly all of the research on net metering focuses only on the impacts on residential or commercial customers.³ By only modeling the impact on a single class of customers, these studies do not permit analysis of cross-subsidization between rate classes. Our analysis considers multiple rate classes and thus permits explicit analysis of cross-subsidization patterns. Second, past studies primarily focus on the adoption decision and rate design. In comparison, our study (1) employs a constant rate design, (2) treats solar adoption as exogenously driven through predetermined RPS requirements, and (3) incorporates effects of solar penetration on the timing of system-wide peak demand. This allows us to clearly isolate the effects of solar generation from these other factors. Third, most related studies in the U.S. focus only on changes in one state, California. Given California's unique rate structures and high electricity prices, the results of these studies may not be representative of how solar carve-outs and NEM programs may impact electricity rates or customer's bills in other regions across the U.S. In contrast, we model these impacts using rate structures and electricity prices derived from representative wholesale electricity markets and electricity distribution companies in the north-eastern U.S.

The results of our study indicate that the fear of a utility “death spiral” may be exaggerated. We find that solar can provide significant electricity generation in 2030 with only a modest increase in bills for non-participants. Even in an extremely aggressive scenario, bill increases for non-participants would not be cost prohibitive. Our findings acknowledge the subsidy of participants by non-participants but also highlight the cross-subsidization between rate-classes. In particular, we find impacts on customer rates and bills depend on the installation pattern. High levels of distributed solar can alter the system peak hour, which affects the allocation of costs.

The article is organized as follows. Section 2 provides a brief summary of the current literature on NEM impacts for customer rates and bills and describes how our study contributes to this literature. In Section 3, we describe the model used to analyze the impacts of NEM at various levels of

PV penetration. This includes discussion of the underlying data and methodology used to simulate these effects. Section 4 presents our results, demonstrates the multiple facets of cross-subsidization issues, and illustrates how the distribution of savings varies across our counterfactual installation scenarios. Finally, Section 5 concludes with a summary, addresses the policy implications of the results from our analysis, and sets the stage for future contributions.

2. Background and literature review

Along with other complementary financial incentives, two common programs for incentivizing solar adoption in the U.S. are renewable portfolio standards and net energy metering. RPS statutes require a certain percentage of electricity generation or retail sales to come from renewable sources. Associated solar carve-outs, where a fraction of the RPS requirement must be accounted for by generation from solar resources, are now commonplace and create additional incentives for adoption of distributed PV systems. As of 2015, 29 states have implemented RPS statutes, and 22 of these states have specific provisions for solar or distributed generation (DSIRE, 2015). In nearly all of these states, RPS requirements interact with the NEM programs offered by some or all utilities.⁴

A large portion of the literature on NEM is focused on California. A combination of excellent solar resource, high electricity rates, and aggressive policy support has made the state a leader in solar installations. This, in turn, has made the consequences more pressing and relevant for California, but other locales are reaching significant penetration levels. Borenstein (2007) provided the early work on calculating bill savings for residential NEM customers of two utilities by analyzing the impact of 2 kW systems. The same data set was later used for an analysis of how rate design affects bill savings (Darghouth et al., 2011). Related studies include Borenstein, (2005, 2008) and Darghouth et al. (2016), which investigate the impact of time-of-use or real-time pricing structures on PV adoption. Cai et al. (2013) have also studied the impact of PV on retail electricity rates using a modeling approach and including a model of the rate case proceeding. The grey literature is rich in this subject area, including a thorough ratepayer impact analysis conducted by the California Public Utility Commission (2013).

Additional studies for other U.S. states are sparse. The literature on the east coast impacts of solar is quite dated (Cook and Cross, 1999). The most similar study to our own analysis is that of net-metering impacts among low-voltage network users in Spain (Eid et al., 2014). Eid et al. (2014) examine cross subsidies, revenue requirements, and cost causality; however, scenarios are focused on variations in program definitions, examining how different net metering timeframes can impact utility cost recovery. Furthermore, Eid et al. (2014) make use of hypothetical solar production; in contrast, our study employs observed solar production data from NEM program participants.

Central to our results are questions concerning cross-subsidies both within and between rate classes. Cross-subsidies have taken on multiple meanings in the literature. In some cases, they refer to subsidization of grid services to solar adopters by other grid users (see Eid et al. (2014) and Picciariello et al. (2015b)). In other cases, cross-subsidies may refer to subsidization across rate classes and voltage levels (see Rodríguez Ortega et al. (2008), Picciariello et al. (2015a)). In our study, we examine both of these cross-subsidization patterns, namely within-rate class and across-rate class subsidization.

3. Model, data, and methodology

In this section, we describe the construction of our model, the

² Not all NEM participants are residential consumers as both small and large commercial customers are also eligible to participate in NEM.

³ The limited exceptions to this include an analysis by the California Public Utilities Commission (2013) and Brown et al. (2016).

⁴ As of 2015, 44 states required some or all utilities to offer some form of NEM programs Database of State Incentives for Renewable Energy (DSIRE), 2015. Map of Net Metering Policies North Carolina State University, Raleigh, NC.

assumptions it incorporates, and the sources of the data used for simulating electricity rates and customer's bills. Given our assumptions and calibrations, we model the impact that varying penetrations of solar electricity has on system costs, as well as impacts on household, commercial, and industrial consumer electricity bills. Our model uses data from wholesale electricity markets, distribution costs, customer hourly demand curves, and solar generation profiles in order to compile the total revenue that customers need to pay. After revenue requirements are calibrated, the model allocates the utility's revenue requirements across different rate classes to simulate a typical set of customer rate structures.⁵ The flexible construction of our model allows us to demonstrate impacts of solar electricity generation requirements under a wide range of counterfactual scenarios.

Our simulation model is relevant for a representative utility that divides its 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 deliver electricity to customers) that is located in a region with a competitive wholesale electricity market. Our model assumes the utility's customer base is divided into three separate classes: residential, small commercial, and large commercial and industrial (C & I) to align with many existing rate structures.⁶ All customers are billed based on a rate structure that is composed of charges based on electricity usage while non-residential customers are also billed based on their level of peak demand.

We first begin by detailing the data and methodology we use to generate customer and electricity market profiles underlying the simulation. We then discuss how solar generation is incorporated into electricity prices and rate structures, including a Net Energy Metering program and how this affects electricity rates and bills in the model. We then present the details of the four different counterfactual scenarios we simulate before presenting the results in of these simulations in the following section.

3.1. Customer load shape profiles

We calibrate our model using aggregate customer load profiles from 2011 to 2014 obtained from a utility operating in the PJM wholesale electricity market. A separate load profile was calculated for each of the three rate classes in our model: residential, small commercial, and large commercial and industrial. Using monthly averages across the four years, a load profile is constructed to simulate representative hourly load for a typical weekday, weekend, and a system peak day for each rate class. Based on these calculations, a total of nine load profiles were constructed from these underlying data. Additionally, these load profiles are unique for each month of the year.

3.2. Hourly solar generation of participants

In addition to the customer load shapes, we build solar generation profiles based on data from solar customers in New Jersey from 2010 to 2013. The customer-level dataset includes both the system size (kW) and hourly solar generation (kWh) for customers with installed PV systems. We divide the hourly generation by the total system size to calculate a capacity factor for every hour of the year. Independent solar profiles are then created for each of the rate classes to account for

⁵ Though we model a distribution utility in an area with a restructured electricity market, we assume that the distribution customers are also electricity customers. Though this may not strictly be true since in many areas customers can choose their electricity provider, all providers would be responsible for the same electricity and renewable requirements. Therefore, for simplicity, and without loss of generality, we model our distribution utility as also providing electricity to all customers.

⁶ We use data from a northeastern U.S. utility to serve as a representation of how an average utility's business is divided between these two groups.

different optimizations (i.e., to maximize peak simultaneity or maximize total output). In addition to the average solar profile, a peak solar profile was created to represent the solar production on a peak demand day in each month for each of the four years.⁷

3.3. Supply cost data

In order to simulate how our representative utility customer's bills will change in response to increased solar penetration, we model the effect of solar on the region's wholesale market prices. Since data in our model are obtained from a utility in the northeastern U.S., we model the PJM wholesale electricity market to simulate wholesale electricity price changes. We focus primarily on changes to the electricity markets through both reduced demand (from NEM customers) and increased supply from grid-scale solar installations. We statistically estimate a market supply curve using historical market data as well as hourly demand using historical data from the PJM electricity market averaged over 4 years. Specifically, we model the hourly, PJM supply curve as a quadratic function of hourly load and a linear function of daily natural gas prices. However, our simulation holds natural gas prices constant over the time horizon of the study. This assumption allows us to isolate changes in electricity rates to only reflect changes caused by increased solar penetration. Nevertheless, due to the size of the wholesale market relative to the utility's electricity demand and our exogenously determined solar requirements, there are limited price changes⁸ in the PJM wholesale market price in response to increased solar penetration.

In addition to wholesale electricity prices, supply costs typically include the costs of electricity transmission, ancillary services that ensure grid reliability, and, in our case, the cost of complying with the solar mandate from the RPS. Firms usually comply with solar mandates by purchasing Solar Renewable Energy Credits (SRECs) from owners of solar installations. In essence, one SREC certifies that 1 MWh of electricity was produced from a solar installation. Retail electricity providers must purchase a sufficient number of SRECs each year to show that they have met the percentage of solar generation required by the relevant legislative statute. If firms do not purchase enough SRECs to comply with the statute, then they must pay an alternative compliance payment (as set forth in the statute) to the regulator for each MWh of generation they are short. This mechanism implicitly puts a price ceiling on the price of SRECs.

Since the market for SRECs tends to be illiquid and volatile,⁹ we are forced to make some assumptions about the future price of SRECs in our simulation. New Jersey has one of the most aggressive solar mandates in the country in combination with a transparent SREC market, we have chosen to model SREC compliance costs as a function of the alternative compliance payment in New Jersey.¹⁰ Other industry analysts have used 50% of the alternative compliance payment, and historically this has been a reasonable estimate.¹¹ Our analysis follows suit. It is important to note that while the non-compliance price drives the maximum value of an SREC, actual SREC prices are dependent on the market supply. After computation of these costs, SREC compliance

⁷ 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.

⁸ These price changes depend on the amount of solar penetration in the model, however, since the PJM market is large (hourly load of 80–100GW) even extremely aggressive assumptions about solar penetration does not change load or PJM electricity prices by more than 1%.

⁹ For example, during energy year 2014 in New Jersey, SRECs were traded at between 40 and 670 dollars per MWh. The number of SRECS traded by month varied from 40,538 to 2,923,695. <http://www.njcleanenergy.com/srecpricing>

¹⁰ While solar costs do vary somewhat throughout the United States, these differences tend to be somewhat small and have begun to converge across locations.

¹¹ In New Jersey energy year 2014 (referenced above) the weighted average trade price over the year was 179.23 which is 53% of the alternative compliance price of 339 dollars.

costs are added to electricity, transmission, and ancillary service costs to construct a total supply cost for the utility.

3.4. Rate design

We model a rate design that is relatively common across many electric distribution utilities in restructured electricity markets in the U.S. This rate design combines volumetric energy charges (cents per kilowatt-hour, ¢/kWh) with peak demand charges (dollars per kilowatt, \$/kW) to recover the costs of providing electricity to the customer. The bulk of the volumetric energy charge is for the cost of electricity generation: the supply rate. The supply rate is used to recover costs from electricity generation purchased on the PJM wholesale markets and SRECs as discussed above.

3.4.1. Supply rate

For all customers, supply rates are distinct for summer and winter. Residential and small commercial customers have day and night rates while for C & I customers the day/night distinction is replaced by on-peak/off-peak rates. These rates are calculated for each rate class by dividing the total cost of energy over a period (summer and winter, days and nights, and on-peak or off-peak) by the amount of energy used during that period. The total cost over a period is simply the hourly price multiplied by the quantity that each customer class uses. The supply rate is then the average cost of energy over a period for each rate class.

3.4.2. Distribution rate

The utility recovers the costs of delivery through a distribution rate that varies by customer class. Residential customers are billed for distribution services using a volumetric energy charge to recover costs associated with delivering electricity to the customer's premises. Our model also incorporates a simple seasonal variation in the residential customer's rate structure, where summer distribution rates (June through September) are higher than winter rates.

Small commercial customers have a more complicated distribution rate structure. They are charged both volumetric energy and demand rates, each accounting for approximately 50% of the total small commercial distribution costs. The volumetric energy charge (\$/kWh) is broken down into summer and winter as well as day and night rates. The demand charge has only a summer/winter distinction.

Finally, large commercial customers have a distribution rate composed entirely of demand charges which again are higher in summer than winter months. The demand charge is based on each customer's maximum hourly demand (kW) in a given month. Typically, maximum demand is based on usage in any 30 minute or smaller periods, but the granularity of our model imposes an hourly restriction.

3.4.3. Rate for miscellaneous expenses

In addition to supply and distribution rates, the final energy charges include volumetric (per kWh), social benefit charges and other miscellaneous fees commonly imposed by public utility commissions to finance market transition costs, securitization of stranded costs, system control charges, energy-efficiency programs and electricity assistance for low-income households. The total value of these fees in our simulation is about 2.5 ¢/kWh. These additional charges for each customer class are assumed to be constant over the analysis period, although the amount of energy over which they are recovered over does vary. This means there are only re-distributional effects within customer classes. Because utilities incorporate them into rates in various forms we chose to categorize them separately. Thus, in the results they are not included in supply or distribution rates, but they are included in customer bills.

3.5. The NEM program

Net energy metering can be applied very differently across jurisdictions with diverging impacts. In our analysis, NEM enables retail customers who generate electricity through their own renewable systems to receive the full retail price for each kWh of electricity their system produces up to, but not exceeding, 100% of their electricity usage over the course of the year. Based on this program stipulation, our simulation constrains customer electricity bills to be non-negative.

In practice, to be eligible for net metering, customers must have an interconnection agreement in place with their utility, which confirms that the generating capacity of their system does not exceed the customer's annual electric needs. The most common NEM program design allows for customers to be credited at 100% of the retail rate for all electricity produced less than their consumption in a given month.¹² Additionally, 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. Previous literature has shown that yearly rolling credits can exacerbate problems of network cost recovery (Eid et al., 2014). In our simulation, no customers receive annual payments for generated electricity, and for all customers, annual consumption of electricity always exceeds annual generation of solar electricity.

3.6. Simulation methodology

We use the above inputs and assumptions to simulate both rates and bills under various solar penetration scenarios. To understand the impact of solar penetration on electricity rates and bills, it is essential to understand the underlying accounting methods used to calculate rates in our model. Our model construction assumes that rates are calculated so that the utility exactly meets its revenue requirement and rate of return. Further, we make additional assumptions to isolate the impact of solar penetration on revenue requirements and market outcomes. First, we assume that demand in the PJM wholesale market remains fixed over the time period of study, except for the effect that newly installed, net metered solar has by reducing demand. Additionally, we assume the representative utility demand is constant across all rate-classes during the period of study. Second, we hold the number of customers in each rate class fixed throughout the simulation period. Holding the ratio of demand and number of customers fixed allows us to comment on the shifting costs between rate classes, isolating these effects from population dynamics or changing energy use patterns which would also influence cost allocation.¹³ Third, the distribution costs of the utility remain constant in real dollars each year. Thus, the utility is not forced to make extraordinary equipment upgrades nor able to defer routine maintenance, a reasonable assumption at these relatively low penetrations.

These assumptions that mean all of the changes in our supply rates are due to changes in demand due to NEM customers, the addition of more grid-connected solar, and changes in the costs and quantities of SRECs, rather than other changes in the electricity market. Moreover, since distribution costs are held constant in our simulation, changes in these rates are a function of the addition of NEM customers and a reallocation of costs across customer classes.

Our simulation takes the inputs and assumptions described above

¹² The "value of solar" has been a hotly contested issue between utilities and the solar industry. While some jurisdictions have rolled back net metering policies or capped participants, the norm remains a retail rate. <https://www.technologyreview.com/s/545146/battles-over-net-metering-cloud-the-future-of-rooftop-solar/>

¹³ In concert, these assumptions are likely to slightly over-state the effects of high levels of solar penetration since growth in electricity demand will mute the effect that solar has on wholesale electricity prices and additional customers would allow the distribution utility to have a larger customer base over which to spread any decrease in sales due to more net metering customers.

and calculates counterfactual electricity and distribution rates. Electricity rates are calculated by using the estimated PJM market supply curve and adding zero marginal cost production from the solar generation in the scenario to the base of the supply curve. This effectively shifts the supply curve outwards and reduces wholesale electricity prices in hours with solar generation. The electricity rate is then determined by this new wholesale electricity price, transmission costs (assumed constant within our simulation), and the cost of SRECs associated with meeting the RPS requirement and dividing by the total quantity of electricity consumed.

The distribution rates are calculated by apportioning distribution costs to each rate-class based on their respective percentage of demand during the peak demand hour of the electricity system, termed “coincident peak demand” and converting this into a rate. The apportionment of total distribution costs to each rate class is affected by solar in two ways: (1) by changing the hour of coincident peak demand, and (2) by reducing demand from a particular rate class. Once the share of total costs attributable to a rate class is determined, they are further divided into energy/demand, summer/winter or day/night rates based on average total and peak monthly usage.

To calculate bills, the rates for each rate class are multiplied by the respective energy usage and fraction of coincident peak demand of the rate class. Average bills are determined by multiplying demand (net of solar) by the supply and distribution rates. This method introduces an implicit constraint on bills, as average bills should also equal the utility's total costs divided by the number of customers. Participant and non-participant demands are also broken out separately and multiplied by rates to determine the diverging effects on these groups. Using the average system size, the solar generation profile, and the required MWh to meet the RPS mandate, we construct an estimate for the number of solar participants in each rate-class. Thus, while all customers face the same rates, NEM customers buy less energy from the utility and thus have smaller bills. Unlike previous studies, we hold the rate structure constant throughout the simulations.

3.7. Solar penetration scenarios

Since New Jersey is widely recognized to have one of the most aggressive solar generation goals in the country and because New Jersey publicly reports disaggregated data on solar installations, we use currently proposed solar mandates in New Jersey as a template for our solar penetration scenarios. New Jersey's current law requires 4.1% of electricity sold in 2028 to come from solar sources with yearly interim goals. We choose our counterfactual simulation scenarios to closely match these requirements, with a base case requirement of 5% by 2030. Further, the allocation of solar installations that are distributed systems (residential, small commercial, and large commercial and industrial participants in a NEM program) versus utility-scale systems are also chosen to match the New Jersey data.

Across our different counterfactual scenarios, we vary three para-

Table 1
Solar scenario definitions.

	Base Case	High Case	High – High Residential	High – High Grid
Solar requirement in 2030	5%	15%	15%	15%
Proportion of grid-connected (utility scale) solar additions	30%	30%	30%	70%
Proportion of NEM solar additions in residential	33%	33%	67%	33%
Proportion of non-residential NEM additions in small-commercial	20%	20%	20%	20%

meters and explore how variations in these parameters affect both electricity rates and customer bills across the three rate classes. These parameters are: (1) the amount of solar generation required in each year of the analysis (determined by the solar mandate), (2) the proportion of solar that is grid-connected versus distributed and therefore participating in a NEM program, and (3) the allocation of distributed solar across three rate classes (residential, small commercial, and large C&I). In each of the scenarios, the current stock and distribution of solar capacity is based on 2015 EIA data on solar generation in the mid-Atlantic region. 30% of installed solar is grid-connected. Of distributed systems, 33% has been installed by residential consumers, 13% by small commercial, and 54% by large commercial and industrial clients.

We first model a “base-case” scenario where we approximate existing New Jersey solar requirements and recent growth rates in solar installation across customer classes.¹⁴ Our base-case specifies that 5% of electricity sold in New Jersey must be from solar by 2030. In the base-case, grid-connected solar accounts for 35% of new, annual installed capacity, residential solar accounts for 35% of new additions of NEM solar, small commercial solar accounts for 13% of new additions of NEM solar, and C&I accounts for 52% of new distributed capacity.

There have been recent proposals in many states to dramatically increase the solar carve-out (and renewable requirements in general) up to twenty or twenty-five percent of sales. Therefore, we compare our base case to three other scenarios where 15% of electricity sold is generated by solar by 2030.¹⁵ This increased solar requirement also accentuates the impacts of solar additions and clarifies the impacts of higher levels of solar penetration. Lower levels of solar additions have more muted effects. We vary the distribution of solar across customer classes and the fraction of grid-connected solar to examine how solar installation patterns affect both rates and bills for customers. These scenarios are summarized in [Table 1](#).

4. Results and discussion

We examine the impacts of these solar penetration scenarios, over time, across customer classes, and between NEM participants and non-participants. The metrics of interest include electricity rates (supply and distribution), electricity bills, shifting peak hours, and differences in bills for solar participants and non-participants. All results are reported in constant 2010 dollars.

It is useful to note that despite making a number of modeling assumptions in our analysis, such as constant demand and natural gas prices across time, all of these assumptions are held constant across scenarios detailed in [Table 1](#). Therefore, comparing across scenarios allows an accurate assessment despite imprecision caused by making necessary assumptions about the rate-making process and economics of the wholesale electricity market.

4.1. Rate impacts by customer class

We begin by investigating how electricity rates change as solar penetration increases. As noted above, the electricity rate is composed of both a supply and distribution component (as well as miscellaneous expenses). When measuring the impacts as a percentage change in rates in 2030 relative to 2015, it is important to note that on average, supply rates (largely electricity, transmission, and SREC costs) are higher than distribution rates leading to smaller percentage changes in

¹⁴ Growth rates of solar installation only affect the flow of new installations. These are added to the existing stock of installations across rate classes.

¹⁵ Since all of the solar adoption in our model is driven by the Renewable Portfolio Standard, changing financial incentives for the adoption of solar either on the federal or state level will not affect the results we display, though of course they will have important distributional effects outside of the electricity rates and bill we discuss here.

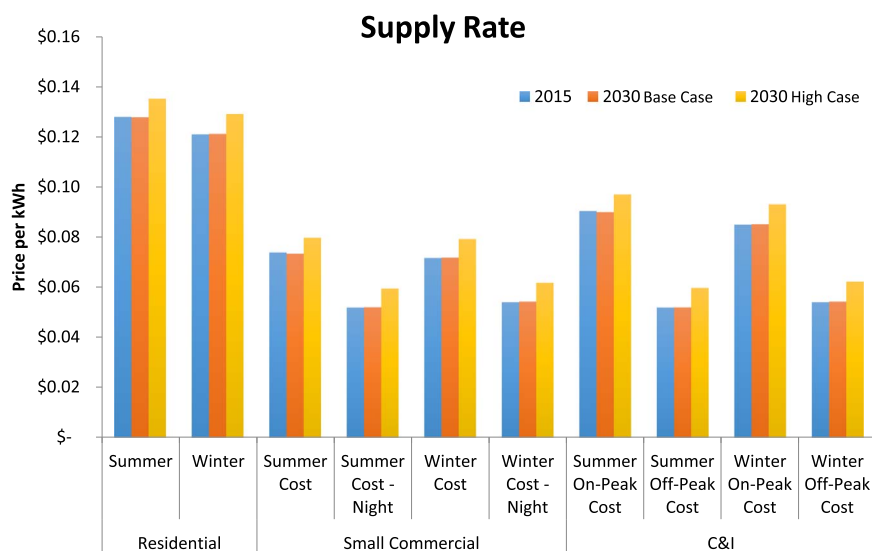


Fig. 1. Supply rates.

supply rates than in distribution rates. Also, both supply and distribution rates are higher in the summer than the winter. Comparing the Base Case and the High Solar scenarios leads to the conclusion that the penetration of solar PV systems has disparate effects on supply and distribution rates.

Fig. 1 presents the changes in supply rates across scenarios relative to 2015. Across all customer classes, supply rates are forecast to remain relatively constant between 2015 and 2030 in the Base Case. The de minimis change is due to slight decreases in wholesale electricity prices and the cost of SRECs. In contrast, there is a significant difference between the base case in 2015 and the high cases in 2030. Supply rates increase in the High Cases due to an underlying cost increase of about 5–10% driven by increases in SREC and ancillary service costs, which are paid for by all customers, and a larger 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, reflecting a doubling of these costs above the Base Case. The amount of solar installed in the High Case is not enough to significantly alter the PJM supply curve to drive down energy costs. This is mainly a consequence of our assumption that changes in market supply are limited to the effects of an RPS in one state of the PJM market. In reality, the broader addition of solar across the region would have a more substantial effect on the PJM supply curve and potentially drive down energy prices throughout the region.

Since differences in supply rates among the high cases are minimal, we only present one of the high solar cases here. The supply rates are primarily impacted by the level of solar installation and not by installation patterns across rate-classes, which have a more pronounced effect on distribution rates.

Comparatively, the impacts on distribution rates are more variable across the scenarios and customer classes as shown in Fig. 2. Results are presented as percentage changes relative to 2015. In the Base Case, distribution rates for residential and small commercial customers are forecast to increase between 2015 and 2030, while they are forecast to stay relatively constant for commercial and industrial customers. For all three rate classes, Base Case changes in distribution rates over the 15-year period increase less than 8% relative to rates in 2015. Similarly, rates for the miscellaneous expenses, described in Section 3.4.3, increase by less than 5% in the Base Case.

Distribution rates change much more significantly in the high solar penetration scenarios. With high solar penetration, distribution rates are

higher in the High Case and the High Residential (Res) Case than in the High Grid Case for residential customers. In contrast, distribution energy rates decline in these cases for small commercial customers. The increase for residential customers (as much as 27%) is due to changes in the hour of peak system demand, which is caused by changes in solar generation which impacts the allocation of distribution costs. When customers are generating their own electricity from behind-the-meter solar, this generation translates to a reduction in demand for the utility and not as additional supply of energy. Since solar is generating energy during the afternoon when the utility system peak has traditionally occurred, it reduces this system peak during those hours. As a result, peak utility system demand shifts and the new peak occurs when solar production drops off in the evening. As the hour of peak demand moves later in the day, the proportion of the peak that is attributed to residential customers grows. Because of this shift, residential customers move from being responsible for 45–53% of total system distribution costs, driving up their costs substantially. In the High Grid case, this transition is not as drastic since the majority of the RPS mandate is met by supply-side installations and, hence, does not differentially affect hourly demand across rate classes. In the 2030 High Grid case, residential customers are only responsible for 46.7% of system peak. In this case, the increase in the distribution rate is driven by reduced sales to NEM customers.

In the High Case, the majority of NEM solar capacity is in the C&I sector, with only 35% of the installation capacity in the residential rate-class. This explains why distribution rates for residential customers increase slightly more between 2015 and 2030 in the High Case compared with the High Res Case. The beneficiary of increasing residential rates in the High and High Res cases are small commercial customers. As the peak shifts later in the day, from 4:00 p.m. in 2015 to 8:00 p.m. in 2030, small commercial customers reduce their percentage of system peak demand. Intuitively, this makes sense because they primarily use electricity during daylight business hours, and their usage begins to decline after 4:00 p.m.

In contrast, demand charges for small commercial and C&I customers generally increase across all scenarios. This is mainly due to reductions in peak demand for NEM customers, which causes rates to increase for all customers in order to recover the same level of costs. In general, the alternative high penetration scenarios adjust the allocation of new solar installations across rate-classes, and our simulations reveal these variations lead to non-trivial changes in the distribution costs attributable to each customer class. Overall, the rate class that installs solar at the highest rate avoids more distribution costs and pushes these charges on other rate classes. Because these scenarios are fit to only approximate current (and alternative) policy, we do not make any conclusions about the absolute value of the impacts. Rather, we emphasize

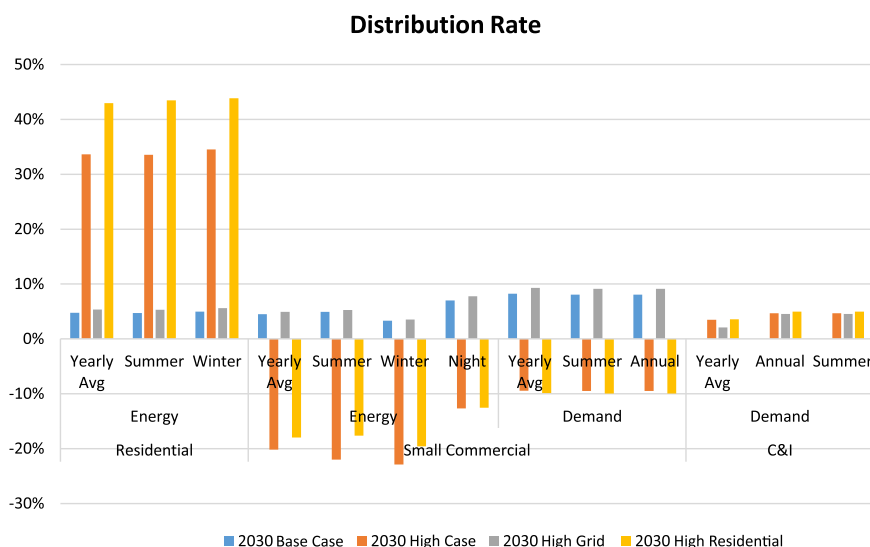


Fig. 2. Changes in distribution rates.

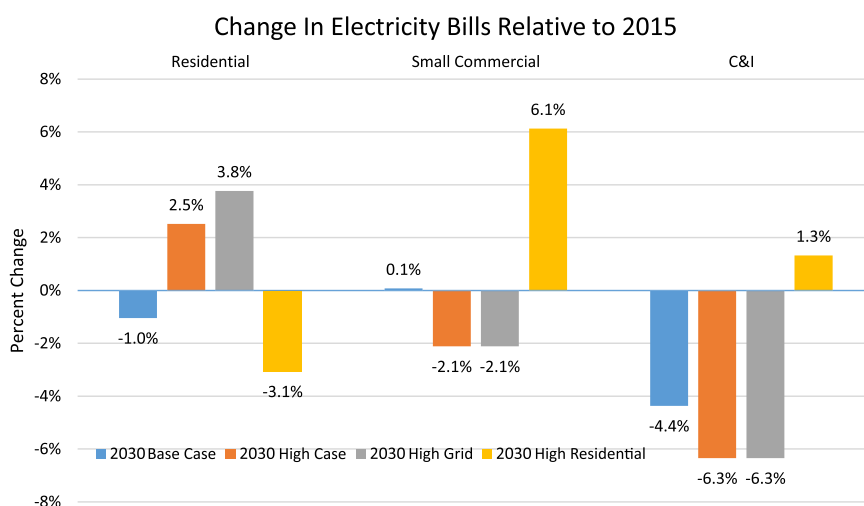


Fig. 3. Average percent changes in electricity bills: 2015 – 2030.

that the results of our simulation illustrate that the impact on rates for a particular class of customers is highly dependent on the level of solar installations in other rate-classes.

4.2. Bill impacts by customer class

When discussing the impacts of solar, it is important to distinguish between electricity rates and bills. Even when rates go up, solar installers buy less electricity and, as a result, pay lower bills. This is a primary source of cross subsidies between participants and non-participants within the same rate-class that has been documented previously (Picciariello et al., 2015b), and we discuss further below. However, unlike existing studies, our analysis also allows for the possibility that cross-subsidies can occur between the rate classes, a phenomenon not yet documented in the literature. In the presentation of bill results, all comparisons are made relative to 2015 non-participant bills.

As with distribution rates, customer bills are dependent on the distribution of new solar installations as shown in Fig. 3. In the Base Case, average residential electricity bills are projected to decrease by about 1%, small commercial customers experience a 0.1% increase in average bills, and C & I bills show the most significant average savings at 4.4%.¹⁶ These savings are, as expected, primarily determined by the

assumptions regarding how the distribution of solar generation is allocated across rate classes. Another reason for significant savings for C & I customers is that their bills are driven primarily by demand charges, which are influenced more significantly by solar since demand peak and demand peak are typically correlated for these customers.

Average percent changes in electricity bills can be misleading as they represent a weighted average of participant and non-participant bills. The weighting changes as more customers install solar so more information can be gleaned from looking at the disaggregated effects, shown in Figs. 4 and 5.

The magnitude of participant bill savings is driven primarily by the assumption of average system size, as expected. Our assumptions for solar system sizes were derived from the Solar Energy Industries Association statistics on system installations.

Non-participant bills are influenced by assumptions about SREC costs. If SREC costs are high, then non-participants will be forced to cover those higher costs. Our Base Case simulations suggest that a significant amount (5%) of solar capacity can be added with only modest (1–2%) increases to non-participant bills. Bill increases in the high penetration scenarios (15%) reflect the cross-subsidization between non-participants and participants. Depending on the rate-class and scenario, average non-participant bills increase between 4% and 14%. When comparing across the high penetration scenarios, we find that the High Grid scenario has a different distribution of bills. This results from a fundamental difference in distributed vs. grid-scale solar

¹⁶ All percentage changes are reported in real terms.

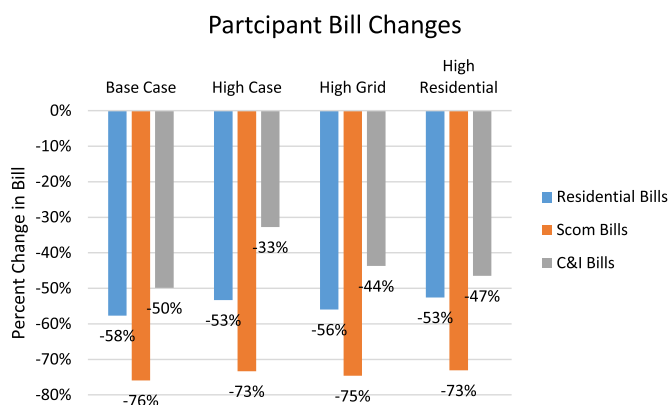


Fig. 4. Percent changes in participant bills: 2015 – 2030.

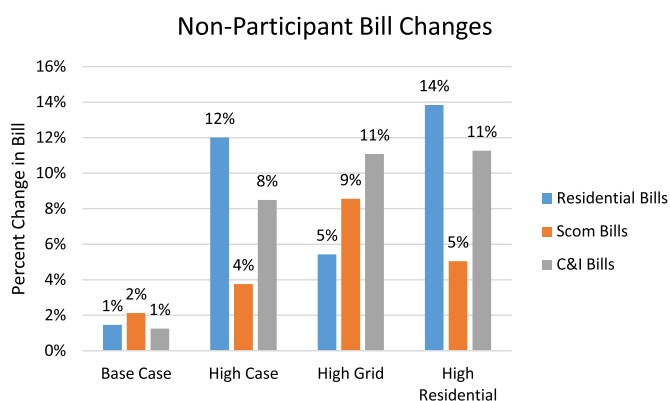


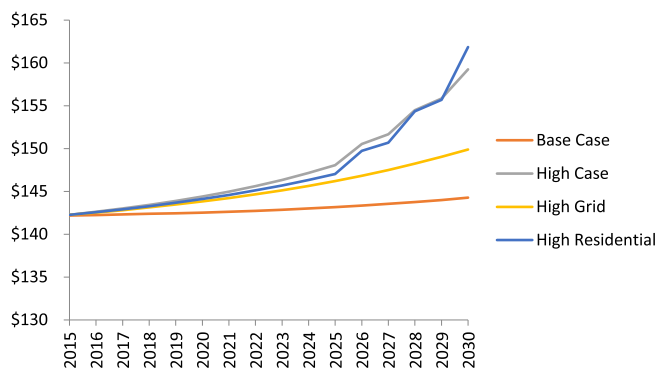
Fig. 5. Percent changes in non-participant bills: 2015 – 2030.

generation. On one hand, grid-scale solar generation shifts the market supply-curve outward and reduces energy prices. As a consequence, when demand is sufficiently inelastic, installation patterns at the grid-scale do not affect the utility's demand. On the other hand, distributed (and particularly NEM) solar generation influences energy prices by reducing the utility's demand. As demand is reduced, at high levels of penetration, the hour of peak demand shifts, as illustrated by the "kinks" in Fig. 6. As solar generation declines at the end of the day, the peak hour shifts to the evening while the demand for electricity remains high. This phenomenon has been documented elsewhere in the literature and termed the "duck curve" (Lazar, 2014). It plays a major role in the emergence of subsidization across rate-classes.

Based on our representative rate-structure, the proportion of costs attributed to each rate class is based on their percentage of peak demand. However, the proportion of demand attributed to each rate-class varies on an hourly basis and, thereby, is not consistent across a typical day. For example, residential customers typically use more electricity in the evenings while small commercial customers tend to use considerably less electricity in the evening. This explains why, in the higher distributed generation scenarios, small commercial bills do not increase as much. However, residential customers are penalized in these cases because their demand accounts for a larger percentage of peak demand.

In the High Case and High Grid scenarios, rates increase for residential customers and the vast majority of residential customers still do not have solar, causing an increase in average bills. However, when a higher percentage of residential customers install solar, the average bills of the rate-class decreases as shown by the High Residential case, although they are still higher than in the Base Case. The forecast in Fig. 3 shows residential customers experience the largest bill increases in the High Case and High Grid scenarios, when supply costs also rise. In addition, residential customers account for an increasing proportion of the utility's coincident system peak, which shifts by four hours to 8 pm, which increases the residential rate-class' share of distribution costs. This can

Residential Bills Over Time



Small Commercial Bills Over Time

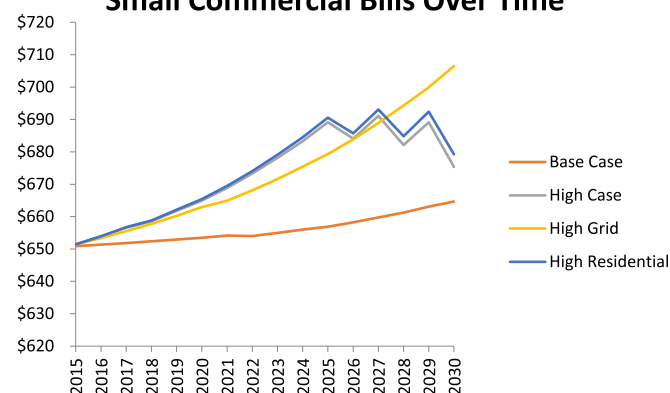


Fig. 6. Non-participant bills over time.

be seen by the discontinuities in Fig. 6.

Small commercial customers also experience higher bills in the High Residential case (but not in the Base Case). Unlike residential customers, the shift in the utility's coincident system peak leads to a reduction in the small commercial rate-class' share of distribution costs. However, this class has the fewest participants installing solar across the scenarios. Furthermore, while their energy rates decrease in only two of the scenarios, their demand rates increase across all penetration scenarios.

C & I customers experience a decrease in bills in three of the four scenarios. Because C & I customers account for the largest share of NEM solar generation in the Base Case, High Case, and High Grid scenarios, their bills decrease by the largest percentage across the rate classes. In the High Residential case, the case in which C & I customers do not account for the largest share of distributed solar generation, average bills increase by slightly more than 1%. Additionally, the peak demand for the C & I customer class shifts away from the coincident system peak. The magnitude of these changes is more significant for C & I customers because their bills are orders of magnitude larger.

5. Conclusions and policy implications

While much of the results section was spent discussing the variations among impacts in the high penetration scenarios, the most important result from this analysis is that a significant amount of solar can be incorporated with little impact on customer bills. In the Base Case, which most closely represents current policy, non-participant bills increase by 2% or less, even when solar accounts for 5% of generation. While the theory that increasing solar penetration will cause rates to go up is correct, the impacts do not appear to be as large as some utility stakeholders' expectations. Our analysis suggests that a utility "death spiral," where rising rates push more and more customers to distributed generation, is not likely to occur with a continued expansion of solar generation. Future research should examine the possible existence of an inflection point past which increasing solar has a more significant impact.

Like many others, our work finds that non-participants subsidize solar adopters. Customers who 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 total electricity sales. Solar-participants avoid these charges and non-participants experience increases in rates and bills as a result. This may have important distributional consequences: if solar non-adopters are systematically poorer and therefore spend a higher proportion of discretionary income on electricity costs, then expanded solar installation under current rate design is regressive.

Our modeling provides a unique contribution by highlighting another form of subsidization. It suggests that customer classes that install solar systems fare better than customer classes that do not. We call this “rate class cross-subsidization”. This phenomenon results from a shift in the hour of system peak demand. Net-metered solar causes a reduction in system demand to the utility. Thus, during the current peak hour, 4 pm, demand is eroded by higher penetrations of distributed solar. This has a direct effect on rates and bills because costs are allocated based on the amount each rate class contributes toward demand during the peak hour. As the peak shifts to the evening, when solar generation diminishes, the residential rate class becomes responsible for a greater percentage of costs. There are often different incentives for customers in each of the rate classes to install solar and efficiencies to scale in doing so, which means the potential for unequal capacity additions is a real possibility.

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. Current pricing policies are imperfect reflections of economic pricing principles, such as aligning charges with cost causation. Current energy (kWh) based pricing schemes do not adequately differentiate the components of the electricity price. The cost of energy, or alternatively of generation, is only about half of retail electricity cost. Other costs include grid infrastructure and maintenance, reserves, administrative costs, and public purpose charges. However, these costs are also recovered primarily through energy charges. Breaking down rates to attribute costs to individual components has become increasingly important with the further implementation of distributed generation, because solar adopters are dramatically reducing their energy purchases from the utility but continue to rely on many of the other services. Nevertheless, it is unclear how these individual components of the grid should be charged. Our analysis suggests that rate design and cost causality may be as much of a political endeavor, deciding who ought to pay for energy services, as much of an economic endeavor, attempting to determine cost causality. Alternative rate designs have the potential to shift the burden of electricity supply, transmission, distribution, and associated services across customers and rate classes.

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 (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, 2016).¹⁷ As

distributed resources become more prevalent, the tradeoffs and consequences of alternative pricing strategies require further analysis. In the likely future of universal smart meters, a new generation of pricing options may emerge.

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¹⁷ In 2014, there were 52 million smart meters installed in the residential sector (U.S. Energy Information Administration, 2016). Smart meters range from basic hourly interval meters to real-time meters with built-in two-way communication.