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The Potential Impact of Increased Renewable Energy Penetration Levels on Electricity Bill Savings from Residential Photovoltaic Systems

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Abstract

Residential photovoltaic (PV) systems in the US are often compensated at the customer's underlying retail electricity rate through net metering. Given the uncertainty in future retail rates and the inherent links between rates and the economics of behind-the-meter PV, there is growing interest in understanding how potential changes in rates may impact the value of bill savings from PV.

In this paper, we first use a production cost and capacity expansion model to project hourly wholesale electricity market prices under three potential electricity market scenarios, using California as a case study. Scenarios investigated include different levels of PV, concentrated solar power (CSP), and wind penetrations in the electricity market. Second, based on the wholesale electricity market prices generated by the model, we develop retail rates (i.e. flat, time-of-use, and real-time pricing) for each future scenario based on standard retail rate design principles. Finally, based on these retail rates, the value of bill savings from PV is estimated for 226 California residential customers under two types of net metering, for each scenario. Results indicate that bill savings from residential PV can vary considerably depending on the temporal trends in wholesale market electricity prices. Under high solar penetration scenarios, we find that time-varying rates are degraded substantially during times of PV generation, reducing bill savings from PV for customers under those rates.

1 Introduction

High penetration of utility scale and behind-the-meter renewables could have a significant impact on wholesale electricity price profiles. These changes would in turn impact retail electricity rates, particularly as retail rate structures shift towards marginal cost pricing with higher temporal resolution. If net metering continues to be the method used to compensate behind-the-meter PV generation, changes in retail rates will impact of the customer economics of behind-the-meter PV.

Residential PV systems are long-term investments. When considering the private economics of residential PV, payback calculations often assume that current retail rates will remain fixed or increase (in real

terms) over the PV system's lifetime. These do not consider the changes in retail rates that could result from increased levels of renewable generation technologies, both utility-scale and behind-the-meter. Future installations of residential solar systems are very dependent on the underlying retail rates, and installation trends could vary greatly with differing retail rate scenarios.

In this paper, we will explore the implications of retail rates resulting from scenarios with high renewable penetrations on residential retail electricity rates and hence the customer economics of residential, behind-the-meter PV. We calculate the private value of solar PV to customers, and do not attempt to quantify the economic or environmental value of the PV electricity generated to society.

Though there has not been published literature directly investigating the impact of high renewable penetration on a variety of electricity retail rates or on the private economics of solar PV, a number of studies have considered related issues. Mills and Wiser (2012) focus on the marginal value of renewables in a wholesale electricity market, and calculate the long-run economic value of variable renewable generation with increasing penetration (the model developed by Mills and Wiser is used in this paper to simulate wholesale price profiles). They find significant drops in the marginal value of PV and wind (to a lesser extent) with increasing penetration in the wholesale market. Other studies, including Lamont (2008), Sáenz et al. (2008), and Sensfuß et al. (2008), have explored the short term and long term wholesale price effects of intermittent generation, which also imply decreasing marginal value of intermittent resources with increasing penetration. E3 and the California Public Utilities Commission calculated *mean* retail rates under an all-gas generation scenario and a 33% RPS scenario to be $0.161/kWh and $0.177/kWh, respectively, adjusted to US$2011 (CPUC 2009). Darghouth et al (2011) and Borenstein (2007) quantified the value of bill savings from PV using prevalent retail rates in CA, which for tiered rates are dependent on the customer's gross consumption. In this study, we assume that rates are not tiered in 2030.

2 Methods and Data

To understand potential impacts of high renewable penetration in an electric grid on the value of bill savings for residential customer, we take the following approach:

1) Model the impacts of various renewable penetration scenarios on hourly wholesale market prices, using a production cost and capacity expansion model;
2) Design three types of residential retail rates (flat, time-of-use, and real-time pricing) for each renewable penetration scenario, assuming full cost recovery of variable and fixed costs;
3) Using two types of net metering to compensate for behind-the-meter residential PV generation, calculate the value of bill savings from PV for residential customers by calculating their annual bill with and without PV generation, for each retail rate type, for each wholesale market scenario.

1.1 Wholesale Market Scenarios

The analysis presented in this paper considers four wholesale market scenarios for 2030: a reference, a 15% PV, and a 33% renewable penetration scenario (see Table 1). In the reference scenario, we assume that no additional renewable generation capacity is built beyond California's 2011 levels. In the 15% PV scenario, utility scale and distributed PV generation is added to meet 15% of total retail annual load. For the 33% RE mix scenario, 33% of the state's annual retail load is met by wind, solar PV, concentrating solar power with 6 hour storage capacity (in a ratio of 50%:35%:15%, respectively), as well as geothermal, small hydro, and biomass electricity generation. The final scenario considered includes 33% renewable penetration, similar to the previously described scenario, with increased levels of pumped hydro storage, totaling 9.9 GW (up from 3.6 GW used in all other scenarios). This scenario is intended to

reflect potential electricity market conditions which could mitigate a decline in value of solar generation and any ensuing declines in value of bill savings from behind-the-meter solar from the high renewable scenario.

For all scenarios, total retail load in CA is assumed to be 341 GWh in 2030, prior to deducting behind-the-meter PV generation, which equates to an average growth rate of 1.2%/year from 2011 until 2030. The renewable generation site selection assumes a geographic diversity through the region for wind and utility scale solar generation sites. For the reference scenario, 50% of total PV generation is assumed to be from behind-the-meter PV generation, and for the other scenarios, 30% of total PV generation is assumed to be behind-the-meter. For all scenarios considered here, half of all behind-the-meter PV generation is assumed to be from residential systems. Assumptions are summarized in Table 1. Assumptions not explicitly stated can be found in Darghouth *et al.* (2012).

Table 1: Wholesale market scenario assumptions

	2030 Penetration Level (% energy basis)				Pumped Hydro Storage	Distributed PV
	PV	Wind	CSP	Other RE	GW	%
Reference	0.3%	4.0%	0.0%	7.4%	3.6	50%
15% PV	15.0%	4.0%	0.0%	7.4%	3.6	30%
33% RE Mix	8.1%	11.5%	3.5%	10.0%	3.6	30%

1.2 Modeling Wholesale Price Profiles

Wholesale price profiles for 2030 are modeled for each wholesale market scenario using an economic investment and dispatch model, developed by and extensively described in Mills and Wiser (2012). Renewable resource capacity additions are fixed, per the scenario definitions described in the previous section. The model then co-optimizes conventional generation additions for energy and ancillary services, incorporating operational constraints and hourly time resolution, to determine long-term economic generation investments and resulting hourly wholesale market prices. Hourly load and renewable generation, as well as the existing generation capacity, are fixed as an input to the model; near zero elasticity is assumed for loads. Given load growth and the fact that some existing generation will retire (for having reached the end of its technical lifetime), new generation will need to be built in order to maintain adequate balance between supply and demand. The model chooses which types of generation is built, and assumes economic equilibrium; that is, the amount of new conventional generation built is such that short-run profit of any new generation is equal to its annualized fixed cost. In most hours, wholesale prices are set to the marginal costs of the most expensive generation needed to meet total hourly load. During peak load hours, however, wholesale prices can increase to levels above the marginal costs of the most expensive generation. During these periods, all plants that are generating earn high scarcity prices, up to $10,000/MWh (an estimate for the value of lost load), which is necessary for peaker plants to recover their capital investments as this is an energy-only market (i.e. no capacity market is included).

The resulting prices allow new generation to exactly recover their fixed costs. We use the wholesale price profiles from this model in the design of residential retail rates, a process described in the next section.

1.3 Retail Rate Structure

Retail electricity rates are designed in order for utilities to recover their costs plus a fair rate of return. Each of the rates modeled in this paper assume full cost recovery. Costs to be recovered include: operating costs of utility-owned generation, the costs of renewable energy procurement, the costs of the transmission and distribution infrastructure, and the cost of the electricity procured on the hourly wholesale market (see Table 2). We assume only the nuclear and large hydro-electric plants are utility

owned. All other thermal generation plants are assumed to be owned and operated by independent power producers, and participate in the wholesale market.[1] Both nuclear and large hydro-electric plants are assumed to run at their full capacity in all of the scenarios considered, and hence the fuel, operation and maintenance costs are equivalent for all scenarios. The costs of transmission and distribution (and other[2]) are assumed to be proportional to today's T&D costs for CA's three largest investor owned utilities, which are also constant throughout the wholesale market scenarios considered. Renewable procurement costs assume a levelized cost of energy of \$0.10, \$0.09, \$0.15 per kWh for solar PV, wind, and solar CSP, respectively (all costs are in US\$2011). The total cost for the procurement of renewable is dependent on the renewable generation mix for each scenario. Finally, the costs of electricity purchased on the wholesale market are also recovered in the retail rate. The amount procured is what is needed to complement utility owned and renewable generation to meet total load.

Table 2: retail electricity rate components

Rate component	**Notes**
T&D & other fixed costs	based on current CA utility rates
Utility-owned generation	Costs to run and maintain hydro and nuclear plants. Capital costs are assumed to be fully depreciated by 2030.
RE purchases	Weighted average of LCOEs for each generation type; for PV, consider wholesale purchases only (utility scale).
Generation purchased at wholesale price	Additional generation needed to meet retail load is purchased on wholesale market.

We consider three types of rate designs in this study: a flat, time-of-use, and real-time pricing rate. The flat rate is not dependent on the time at which the electricity is consumed. The time of use rate is dependent on the season and period of the day in which electricity is consumed. The real-time rate potentially changes every hour, and is dependent on wholesale electricity prices.

1.3.1 Flat Rate

There are two components to the flat rate: a volumetric charge derived from the utility's wholesale market purchases (R_{gen}) and a volumetric charge to recover all other costs (R_{adder}). R_{gen} is the portion of the retail rate to recover the cost of wholesale purchases over all hours divided by total billable residential load. Each hour, we assume that the portion of residential load not met by utility-scale renewable energy and utility-owned generation is purchased on the wholesale market. The total billable residential load is the residential load which is not displaced by net metered PV generation compensated at the full retail rate. In summary:

$$R_{gen} = \frac{\sum_h \left(L_{h,res} - G_{h,res\ PV}\right) \cdot \left(1 - r_{h,uog} - r_{h,util\ RE}\right) \cdot P_h}{\sum_h \left(L_{h,res} - G_{h,res\ PV}\right)}$$

where $L_{h,res}$ is the residential load in hour h, $G_{h,resPV}$ is the residential PV generation compensated at the full retail rate in hour h, $r_{h,uog}$ is utility-owned generation as a percentage of net load in hour h (after deducting behind-the-meter PV), $r_{h,util\ RE}$ is utility renewable generation as a percentage of net load in hour h, and P_h is the wholesale price in hour h.

R_{adder} is calculated by dividing all other costs by the billable residential load. Here we assume that the residential sector is responsible for residential T&D costs, and a proportion of the utility-owned and renewable electricity generation costs. This proportion is set to the residential percentage of total retail load. In summary:

$$R_{adder} = \frac{C_{T\&D} + \left(C_{uog} + C_{RE}\right) \cdot r_{res}}{\sum_h \left(L_{h,res} - G_{h,res\ PV}\right)}$$

where $C_{T\&D}$ is the total transmission and distribution costs for residential customers, C_{uog} is the costs of utility-owned generation, C_{RE} is the total costs of renewable energy procurement, r_{res} is the residential percentage of total retail load (net of behind-the-meter generation).

1.3.2 Time-of-Use Rate

Under the time-of-use (TOU) rate, residential customers are charged different volumetric rates depending on the time at which the electricity is consumed. In this study, we have chosen to divide the year into two seasons (a high priced and a low priced season), and three rate levels in each season (peak, mid-peak, and low). The TOU rate periods are defined differently for business and non-business days.

The seasons and TOU periods for each of the seasons are calculated using k-means clustering algorithms. This method partitions wholesale prices into clusters of contiguous time periods. The clusters are chosen in order to minimize the sum of square error from the mean of the cluster. More specifically, the seasons are determined by:

1) Selecting two initial centroids (i.e. zero and maximum average daily price)
2) Finding two clusters of contiguous days (i.e. S_1 and S_2) that minimize:

$$\sum_{j=1}^{2} \sum_{d \in S_j} \left(p_d - \overline{p_j}\right)^2$$

where p_d is the mean daily price in day d and $\overline{p_j}$ is the mean daily price in S_j. We assume that each season begins on the first day of the month and has a minimum of 4 months.

3) Recalculating the centroids $\left(\frac{\sum_{d \in S_j} p_d}{N_j}\ for\ j = 1, 2\right)$
4) Repeating steps 1-3 until centroids converge.

A similar procedure is repeated to determine TOU periods for business days (weekdays excluding federal holidays) and non-business days (including weekends and federal holidays). We assume that business days have 3 TOU periods (peak, mid-peak, and low priced) and non-business days have 2 TOU periods (mid-peak and low). TOU periods have a minimum of 2 hours in length and a business day can be have up to two peak periods.

Similar to the flat rate, the TOU rate has two components: R_{gen} and R_{adder}. The volumetric adder, R_{adder}, is the same as for the flat rate. The portion of the bill derived from wholesale purchases, $R_{gen,T}$, is different for each of the TOU price levels T (low, mid, and high) for each of the seasons.

$$R_{gen,T} = \frac{\sum_{h \in T}\left(L_{h,res} - G_{h,res\ PV}\right) \cdot \left(1 - r_{h,uog} - r_{h,util\ RE}\right) \cdot P_h}{\sum_{h \in T}\left(L_{h,res} - G_{h,res\ PV}\right)}$$

When $R_{gen,mid}$ is less than 5% lower than $R_{gen,peak}$, the two periods are combined into a single mid-peak period (i.e. the peak period is eliminated), and $R_{gen,mid}$ is recalculated.

1.3.3 Real-Time Pricing

The variable portion of the real-time pricing (RTP) rate is set to the wholesale price, potentially changing every hour. Additional revenue is necessary, however, to recover the full costs of service (including T&D, RE purchases, and utility-owned generation). This residual revenue requirement (*RRR*) is the difference between the total revenue requirement and the revenue from the variable portion of the bill, or:

$$RRR = \left(C_{T\&D} + \left(C_{uog} + C_{RE}\right) \cdot r_{res}\right) - \sum_{h}\left(\left(L_{h,res} - G_{h,res\ PV}\right) \cdot P_h\right)$$

The residual revenue requirement is assumed to be recovered through a volumetric charge for all residential customers, which we term the residual revenue adder (R_{RRA}).

1.4 Behind-the-Meter PV Compensation and the Calculation of Value of Bill Savings

In this paper, we have chosen two compensation mechanisms for electricity generated by residential PV systems. The first is *net metering*, where PV generation displaces energy consumption billed, regardless of *when* the PV system generates electricity. The second we term *hourly netting*, where a customer's PV generation can displace consumption within an hour but electricity generated beyond hourly consumption is compensated at wholesale electricity rates. Since $G_{h,resPV}$, the residential PV generation compensated at the full retail rate, is lower with hourly netting than with net metering, the volumetric adder, R_{adder}, is slightly greater under net metering than hourly netting.

Our bill analysis relies on 15-minute interval load data from a sample of residential customers located throughout the state of California, spanning the 12-month period from October 2003 through September 2004. These load data were collected through a previous study on critical peak pricing (Charles River Associates, 2005), and were made available for the present analysis. After all data cleaning operations, hourly consumption data for 226 customers were ultimately used in this analysis.

The customers within the data sample are somewhat larger than the typical residential customer of either utility, but are smaller the typical net-metered residential customer (see Darghouth et al. 2011 for more details on the customer load data). The residential customers in the data sample did not have PV systems installed. Thus, for each customer, hourly PV production was simulated using the National Renewable Energy Laboratory (NREL)'s PVFORM/PVWatts Model and the National Solar Radiation Database (NREL 2012). The simulated PV production data consists of hourly AC electricity generation at 73 weather stations located throughout California, for the same 12-month period as the customer load data (October, 2003 through September, 2004). For our analysis, we used simulated production for a south-facing (180^0 azimuth) system with a 25^0 tilt, as this is the azimuth that produces the maximum annual electricity generation per kW of installed capacity in the northern hemisphere, and 25^0 is a typical angle for a sloping rooftop.

For each paired set of customer load and PV production data, the simulated hourly PV production was then scaled so that total annual PV generation would be equal 75% percent of the customer's annual consumption (i.e. a 75% PV-to-load ratio). For comparison, among the actual population of residential PV customers in California, the average PV-to-load ratio is approximately 56% for PG&E residential customers and 62% for SCE residential customers (DeBenedictis 2010).

3 Results

In this section, we present the residential electricity retail rates resulting from the three wholesale market scenarios considered, and the value of bill savings from PV using these rates under two types of net metering.

1.5 Retail Rates

1.5.1 Flat Rate

As described in section 1.3.1, the flat rate consists of two components, one related to wholesale market purchases (R_{gen}) and one related to all of the utility's other costs to be recovered by residential rates (R_{adder}). These rate components, as well as the total flat retail rate (R_{total}), are shown in Table 3. This table assumes net metering for all customers with behind the meter PV[1].

Table 3: Retail rate components for the flat rate under reference, 15% PV, and 33% RE scenarios, in $/kWh

Scenario	R_{adder}	R_{gen}	R_{total}
Reference	0.115	0.064	0.179
15% PV	0.134	0.060	0.194
33% RE	0.140	0.052	0.192

R_{total} for the reference wholesale market scenario is $0.179/kWh, which is slightly lower than for all scenarios with higher renewable penetrations. The total wholesale electricity purchase costs for the high renewable penetration scenarios are slightly lower than for the reference scenario, since less electricity needs to be purchased on the wholesale market, which leads to a slightly lower R_{gen}. However, this does not imply that the average costs of electricity purchased is higher for the reference scenario; R_{gen} is not the average costs of electricity purchased on the wholesale market (it is the volumetric charge to recover total market purchase costs). R_{adder} is higher for the high renewable scenarios than for the reference scenario, due to the additional renewable procurement costs, which counters the effect of the lower R_{gen} and leads to a higher R_{total}. The highest total flat rate is from the 15% PV penetration scenario, a result of the higher costs of PV electricity acquisitions.

1.5.2 Time-of-Use Rate

Time-of-use (TOU) rates allow utilities to send price signals to customers based on historical wholesale price patterns. As wholesale price patterns change, utilities will have to adapt their TOU rate periods and rates to conform to these shifting wholesale price profiles. The most significant changes in the TOU rates

[1] With residential PV customers all under hourly netting, R_{adder} is slightly lower than assuming net metering for all behind-the-meter systems. Though the total costs of renewable energy procurement (C_{RE}) increases slightly to account for the payments for net exported behind-the-meter generation (at wholesale prices), the residential PV generation compensated at the full retail rate in hour h ($G_{h,resPV}$) also decreases, leading to a net decrease in R_{adder}, as per the final equation of section 1.3.1.

from the reference scenario to the high renewable scenarios are the shift in the time periods; the rates charged for each of the periods change as well, though not as significantly. For the 15% PV and 33% RE mix scenarios, high PV penetration erodes wholesale prices at times when PV generates electricity, as zero marginal cost PV generation displaces higher marginal cost generation. The high period in the high season shifts from 1pm-7pm for the reference scenario to 6pm-9pm in the 15% PV scenario and 5pm-9pm in the 33% RE mix scenario, as labeled in the top left panels of Figures 1-3.

Table 4: Time-of-use rate for all periods and season

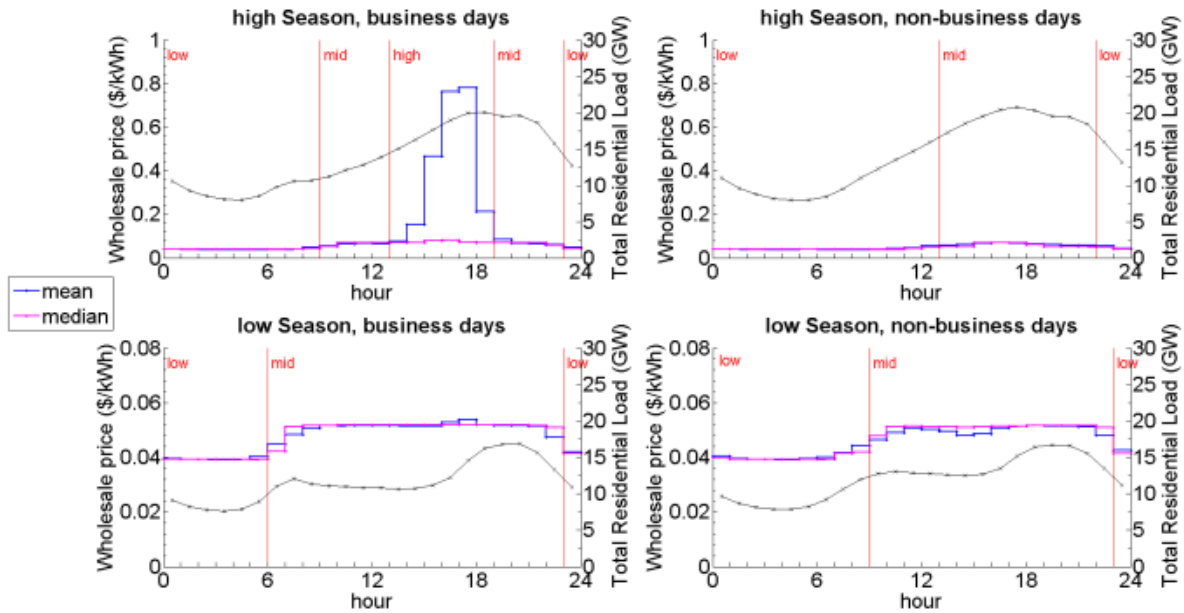
	Low Season			**High Season**		
Scenario	**Off-peak**	**Mid-peak**	**Peak**	**Off-peak**	**Mid-peak**	**Peak**
Reference	0.142	0.150	-	0.145	0.164	0.493
15% PV	0.156	0.166	0.171	0.158	0.204	0.701
33% RE	0.159	0.164	0.167	0.162	0.186	0.572

The rates for each of the TOU periods also change to reflect the shifting costs of generation within those periods. The largest differences in calculated retail rates are in the high season's peak period, which increase from $0.493/kWh in the reference scenario to $0.701/kWh and $0.572/kWh in the 15% PV and 33% renewable scenario, respectively (assuming all customers are on net-metering). The increase in the high season's peak rate observed for the 15% PV and 33% renewable mix scenarios is difference is not due to increased peak price levels in the wholesale market, but rather the length of the peak period. The wider the wholesale price peak shape, the longer the peak period, and hence more low priced hours are included in the average peak rate. The 33% renewable penetration scenario has a wider wholesale peak shape than the 15% PV scenario, due to increased storage from the CSP, leading to a lower peak TOU rate. The peak price for the 33% renewable scenario with storage is lower than for the reference scenario, not only because the wholesale price profile peak shape is wider due to the storage, but also because the peak levels are much lower, leading to lower cost of electricity purchases in the wholesale market.

As displayed in Figure 1, for the reference scenario, there is a single peak TOU period preceded and followed by mid-peak and low periods for high season business days, and only a mid- and low period for low season business days. The mean wholesale price peak is an order of magnitude higher than the median wholesale price peak, which is due to a number of very high priced hours skewing the mean upwards. The median hourly wholesale prices during the high price period of the high season range from $0.070/kWh to $0.081/kWh, while the mean hourly prices range from $0.067/kWh to $0.781/kWh. Ten percent of all hours in the high season's peak period have a wholesale price greater than $0.50/kWh, with a mean price of $3.14/kWh. The prices during the other TOU periods are more consistent (i.e. there are no price peaks which skew the mean prices upwards), and clear TOU periods can still be delimited.

The average residential load curve for CA, overlaid on Figures 1-3, only accounts for about one third of total retail load. Non-residential load peaks earlier in the day, and thus, with low levels of renewable generation in the reference scenario, peak residential load in the high priced season occurs at the tail end of the high TOU period. On average, 32% of residential load (and 61% of residential costs) during business days in the high season occurs in the peak period, in the reference scenario.

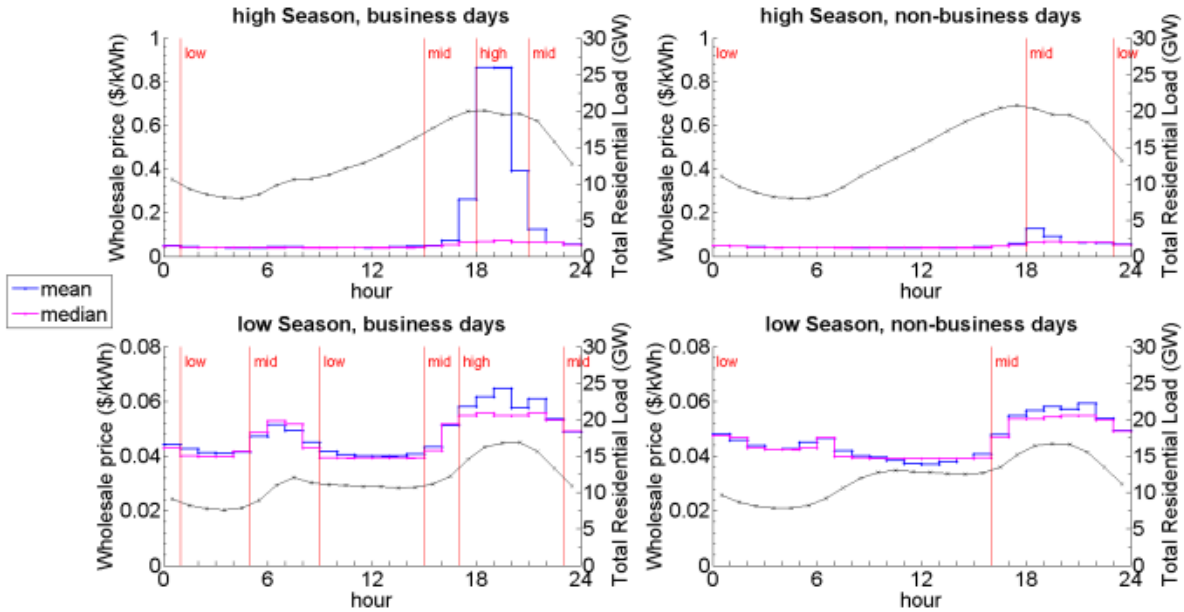
Figure 1: Wholesale prices and TOU periods for reference scenario (Notes: vertical red bars indicate the start of the TOU periods for each day type; the black curve indicates total residential load; the blue and pink lines indicate the mean and median wholesale)



The peak period in the high season in 15% PV scenario shifts and narrows to 6-9 pm; as with the reference scenario, it is also preceded and followed by a mid-peak and low period, as shown in Figure 2. There is a bimodal period structure for business days in the low season with much smaller wholesale price differentials; a single high period in the late afternoon and early evening preceded and followed by a mid-period, and mid period in the morning preceded and followed by a low period. Non-business days in both seasons have a mid-price period in the late afternoon and early evening with a low priced period at all other times.

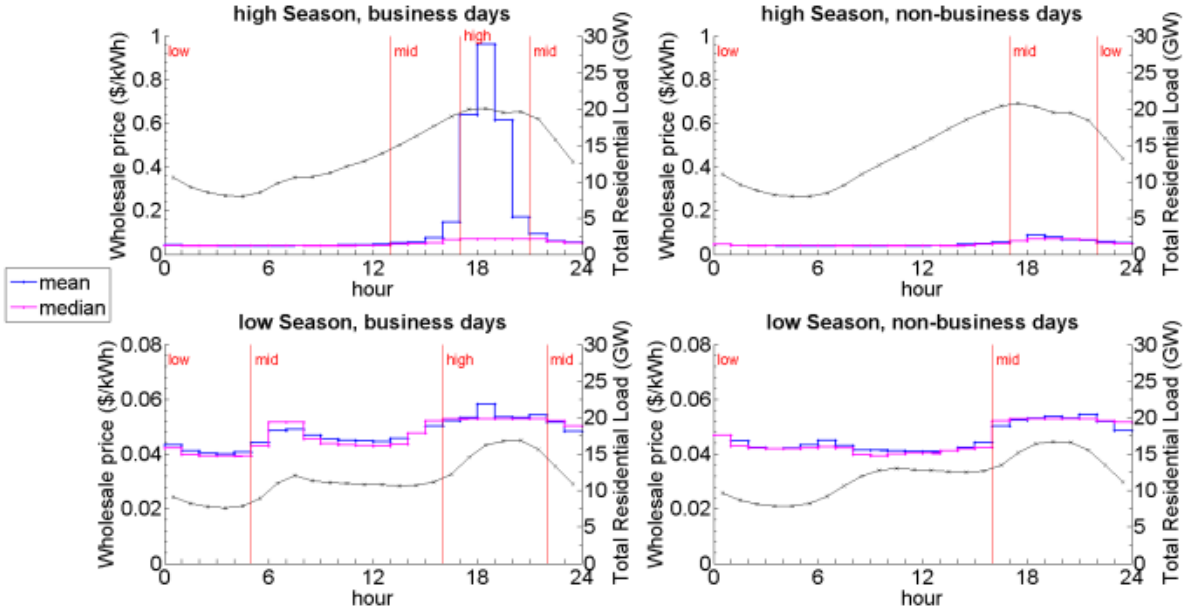
As with the reference scenario, the mean price during the peak period in the high season is an order of magnitude greater than the median price; mean prices range from $0.392/kWh to $0.863/kWh, while median prices only range from $0.065/kWh to $0.074/kWh. Almost 15% of all hours in the high season's peak period have a wholesale price greater than $0.50/kWh, with a mean price of $4.02/kWh. These hours, which reflect scarcity pricing, drive $R_{gen,\ high}$ up to $0.567/kWh. Only 20% of hours with a wholesale price greater than $0.50/kWh occur in times other than the high season's peak period (in the high season's mid-peak period), with a mean wholesale price of $1.12/kWh.

Figure 2: Wholesale prices and TOU periods for 15% PV scenario (see notes in Figure 1 caption)



The price periods for the 33% RE mix scenario are similar to that of the 15% PV scenario, though the peak periods start an hour earlier and are longer in the high season. Also similarly, the mean price during the peak period in the high season is an order of magnitude greater than the median price; mean prices range from $0.149/kWh to $0.964/kWh, while median prices only range from $0.068/kWh to $0.071/kWh. The inclusion of lower priced hours in the peak period leads to a lower $R_{gen,\ peak}$ than for the 15% PV scenario. Other periods are similar, albeit lower priced, to the 15% PV scenario.

Figure 3: Wholesale prices and TOU periods for 33% RE mix scenario (see notes in Figure 1 caption)



1.5.3 Real-Time Pricing

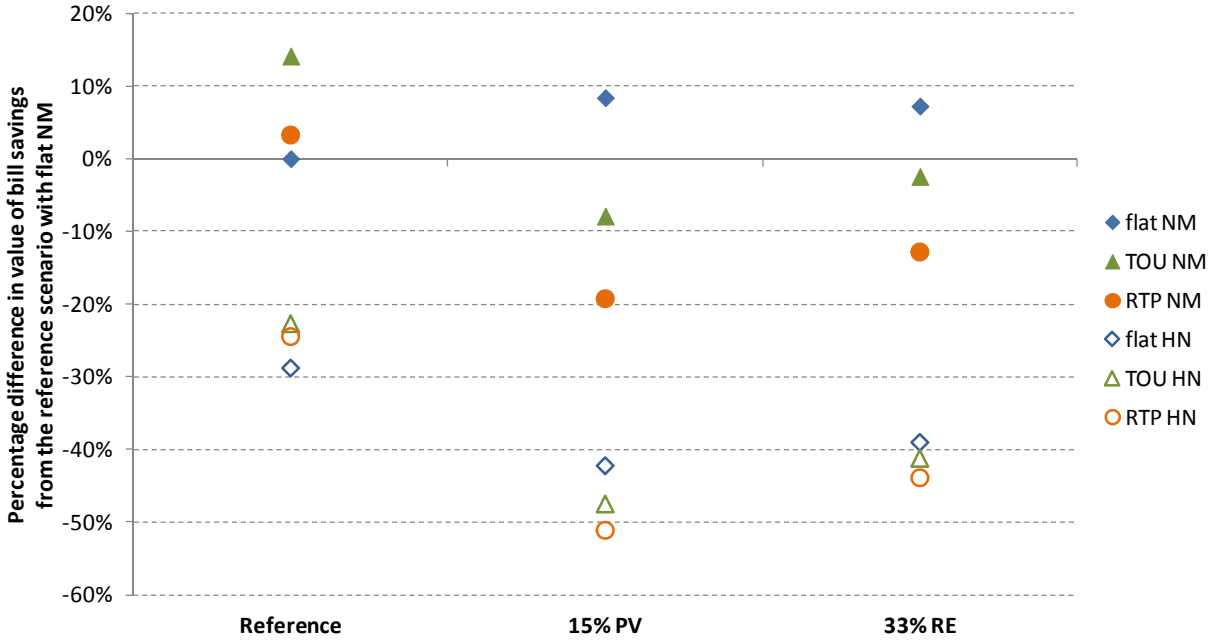
Real-time pricing (RTP) exposes customers to wholesale price changes on an hourly basis. The hourly price charged for customer's usage in each hour is equal to the hourly wholesale market price plus the residual revenue adder (R_{RRA}), which is required in order to recover all remaining revenue requirements and differs for each wholesale market scenario. With the reference scenario, a residual revenue adder of \$0.085/kWh is needed assuming net metering or hourly netting (the low level of behind-the-meter PV generation leads only to small differences between the two PV generation compensation schemes). Under the 15% PV and 33% RE scenarios, R_{RRA} is \$0.096/kWh and \$0.094/kWh for net metering and \$0.094/kWh and \$0.093/kWh for hourly netting, respectively. R_{RRA} is greater for the high renewable scenarios as the levels of residential behind-the-meter PV lead to lower net residential load from which the revenue is recovered, in addition to the larger renewable purchase obligations.

Under the reference scenario with RTP, 1.7% of total median residential load in the modeled year 2030 are during hours with wholesale prices above \$0.10/kWh; this contributes to 24.8% of the bill of an average customer without PV (assuming a zero elasticity of demand). This increases slightly to 26.7% under the 33% RE mix scenarios; scarcity prices occur during a similar number of hours in all scenarios as peak generators need to recover their fixed costs (though the specific hours during which scarcity pricing occurs differs with each scenario).

1.6 Value of Bill Savings

We calculated annual utility bills for each customer from our dataset, both with and without a PV system, under each retail rate and PV compensation schemes, and for each wholesale scenario. For the reference scenario, the value of bill savings for customers under the flat rate with net metering is \$0.179/kWh, since all PV generation displaces consumption at that rate regardless of the customer's temporal load shape or consumption level. Figure 4 plots the percentage difference between the median value of bill savings across all 226 customers relative to that of the flat rate with net metering for each combination of retail rate, PV compensation scheme, and wholesale market scenario.

Figure 4: Median value of median bill savings from PV under each retail rate, compensation scheme, and wholesale market scenario, relative to the median value under the flat rate with net metering



In the reference wholesale market scenario, the bill savings from PV with real-time pricing and net metering is just 3% larger than for the flat rate. The difference is relatively small, as on RTP, most PV generation is compensated during hours where prices are lower than the flat rate, which largely offsets the higher levels of compensation received during the small number of very high priced hours. Residential customers with PV systems with net metering would be compensated 14% more under the TOU rate than the flat rate. Though all TOU periods except for the high season's peak period are lower than the flat rate, a large enough portion of PV production occurs during that period (15% in the median case) to make up for the comparatively lower levels of compensation under the other TOU periods. The value of bill savings for customers under the TOU rate is higher than under RTP, due to the averaging of the high wholesale prices over a larger number of hours when PV generates.

Hourly netting decreases the value of bill savings for PV customers, since customers do not displace the adder portion of their rate for hourly PV generation produced in excess of hourly consumption. Under the reference scenario and the flat rate, a customer's value from bill savings would be 29% lower than under the net metering. A customer would fare better under RTP or TOU than the flat rate with hourly netting, for similar reasons as for net metering. However, the differences in value of bill savings between the rates are not as pronounced under hourly netting. The excess generation within an hour is compensated at the wholesale rate regardless of the underlying retail rate, and hence a smaller portion of the net load is billed at the retail rate, reducing the difference between the total bills.

Under the high renewables scenarios, the flat rate increases slightly on average, and hence the value of bill savings with net metering increases slightly, compared to the reference scenario. In contrast, the value of bill savings with the RTP rate and net metering decreases under the high renewables scenarios, due to the shift in peak wholesale prices to times when solar PV does not generate electricity; only 7% and 12% of total mean compensation is from hours with rates greater than $0.50/kWh for the 15% PV and 33% RE mix scenarios, respectively. This decrease in value of bill savings occurs despite a modest increase in the adder portion of the rate (R_{adder}), resulting from increased renewable procurement costs. Similarly, the value of bill savings for TOU with net metering falls significantly with increased solar penetration. As

described in section 3.1.2, the high priced TOU period during the high season shifts to times when there is almost no solar generation. Total compensation for PV generation during this high-priced period falls to 2% and 6% for the 15% PV and 33% RE mix scenarios, respectively. 92% and 98% of PV generation occur during TOU periods with rates lower than the flat rate for the 15% PV and 33% RE mix, respectively, and the average compensation for the PV generation is lower than for the flat. With high PV penetrations, the value of bill savings for customers with TOU is greater than with RTP with net metering. Customers on the TOU rate benefit from averaging of wholesale prices over all hours within the high season's mid-peak period, since higher wholesale prices late in the mid-peak period (when PV generates the least) raise the mid-peak rates.

For the high renewables wholesale market scenarios, customers under the flat rate with hourly netting observe a decrease in value of bill savings when compared with the reference scenario, even though the flat rate is higher. The loss in value of bill savings attributable to the portion of the customer's PV generation compensated at wholesale rates is greater than the gain in value attributable to the portion of PV generation that displaces customer load within the hour, compensated at the flat rate. For customers under the TOU and RTP rates with hourly netting, all PV generation decreases in value, due to the decrease in the retail rate and wholesale prices as compared with the reference scenario.

The decreases in value of bill savings for the 33% RE mix scenario follow the same trends as for the 15% PV scenario, but value erosion for all rates with a time-varying component is not as great as for the 15% PV scenario. There are two principal reasons for this: there is less solar generation in the 33% RE mix scenario (8.1% PV and 3.5% CSP with storage), and the storage from the CSP capacity flattens the price peaks, leading to increased wholesale prices during times of PV generation.

4 Conclusion and discussion

The future value of bill savings from residential PV will be dependent on the wholesale market generation mix, retail rate design, and how the PV generation will be compensated. We find that as retail electricity rates move towards time-varying pricing, high solar penetrations in the market could lead to an erosion in the bill savings from behind-the-meter residential PV. Wholesale prices decline when there is high PV generation under a high solar penetration scenario, as the marginal costs of generation decreases. Changes in wholesale electricity price profiles would lead to a change in retail rates, and time-varying rates would be lowest at times when PV generates. As long as residential PV generation is compensated at retail rates or wholesale rates, the compensation per kWh would be lower in a scenario with high solar penetration than for one with low penetration, all else similar.

We note a few general trends from the three scenarios explored.

1) Relative to the reference case, for the scenarios considered, the flat rate with net metering leads to an increased value of bill savings from residential PV, ranging from 7% to 8% higher than customers with the flat rate and net metering, under the reference scenario, in the median case.
2) Hourly netting erodes value of bill savings for any given scenario by 22% to 26%, relative to net metering, dependent on the scenario and customer's rate option.
3) For the reference scenario, the rate option that provides the greatest value to a residential PV system owner is the time-of-use rate, followed by the real-time pricing rate, followed by the flat rate.
4) In stark contrast, for the two other scenarios, the flat rate provides the most value from PV, followed by the TOU rate, followed by RTP, for a given compensation scheme.
5) Customers under the RTP rate with hourly netting in the 15% PV scenario receive the lowest value of bill savings of all rates, compensation schemes and scenarios considered (51% lower than that of customers under the flat rate with net metering in the reference scenario). Conversely, customers

under the TOU rate with net metering in the reference scenario receive the highest value from PV (in the median case, 14% higher than that of customers under the flat rate with net metering in the reference scenario).

This analysis could be extended to gain a more detailed understanding of the drivers leading to changes in the value of bill savings from residential PV, *how* different elements of a wholesale market impact value of bill savings (e.g. the impact of demand response, increased utility-scale storage, natural gas prices, or a carbon price). Another valuable contribution would be to quantify how a customer could mitigate the erosion in their value of bill savings from PV generation with customer-sited storage. These will be further investigated in a future study.

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[1] Though utilities enter bilateral contracts with generators, in the long term, these should approximate average market prices (plus a risk premium).

[2] Other costs include a public purpose programs charge, a reliability services charge, and a competition transition charge. We recognize that the existence and magnitude of these charges in 2030 is uncertain.