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The distributional impacts of residential demand charges

Ryan Hledik*, Gus Greenstein

The Brattle Group, United States

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ABSTRACT

Demand charges have recently emerged as an important feature in many proposals to reform residential electricity rates. Relying on load and income data for more than 1,000 utility customers, the authors provide an assessment of the impact this rate design could have on residential customer bills and examine the potential for home energy storage to enhance bill savings. One encouraging finding: demand charges do not disproportionately impact low-income customers relative to the rest of the sample.

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1. Introduction

Residential electricity rate structures have remained essentially unchanged for the past century. However, recent advancements in energy technologies such as smart metering, distributed generation, and the "connected home" have necessitated a new look at rate design. The existing rates, which typically consist of a modest fixed monthly charge and a volumetric (i.e., cents-per-kilowatt-hour) charge, are beginning to be replaced with more sophisticated options. These new options are intended to better reflect the cost of generating and delivering electricity and to provide customers with opportunities to reduce their bills through changes in electricity consumption patterns.

One rate design option that is receiving increasing interest in the industry is the introduction of a demand charge. Demand charges recover some portion of the utility's cost by charging the customer based on his/her maximum instantaneous demand for electricity (measured in kilowatts), rather on his/her total monthly consumption (measured in kilowatt-hours).[1] There are several potential benefits to this approach if the demand charge is well designed and carefully implemented. It could improve fairness and equity in cost recovery by more accurately charging customers for their use of the power grid. It would also provide an incentive for demand reductions and adoption of emerging energy management technologies, which could reduce system resource costs and customer bills. Demand charges have been offered to commercial and industrial customers for decades.

Given the industry's growing interest in this rate design concept, it is critical to understand the implications of the rate's widespread adoption. Two questions in particular are regularly asked. First, what will be the impact of demand charges on customer bills, particularly those of low-income customers? And second, to what extent will demand charges improve the economics of emerging home energy technologies, specifically those aimed at helping customers manage their peak demand, such as distributed energy storage?

In response to those questions, this study provides an initial assessment of the impact that demand charges could have on customer bills and on the economics of distributed energy storage. The article is not intended to comprehensively answer these questions. Rather, it frames the issues and provides initial insights using load data for a sample of utility customers in Vermont. The findings of this study should be considered a starting point for further, detailed analysis of these issues using an expanded dataset and regional case studies.

1.1 The trend toward residential demand charges

While demand charges are not a new concept – they have been a common feature of rates for commercial and industrial customers for decades – it has been relatively unusual to find them in residential rate offerings. A recent survey identified 19 U.S. utilities offering residential demand charges (Hledik, 2015). In some instances those offerings have significant enrollment. For example, Arizona Public Service (APS) has 117,000, or roughly 10% of its residential customer base, on a rate with a demand charge. In most cases, however, enrollment is limited.

* Corresponding author.
E-mail address: ryan.hledik@brattle.com (R. Hledik).

[1] Typically, a demand charge is not based on a truly instantaneous measure of demand, but rather an average over an interval of 15, 30, or 60 min. And, as discussed later, there are a variety of ways in which demand could be defined for the purposes of billing a demand charge, such as maximum demand during a period coincident with the system peak, maximum demand during a period coincident with the class peak, or maximum demand based on the customer's own peak over the course of the month. Other alternatives are also available.

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Recent developments suggest that there could soon be an increase in residential demand charge offerings. Several utilities have proposed demand charges in the past couple of years. Georgia Power, for instance, introduced a voluntary three-part rate in 2014 (Georgia Power, 2016).[2] Salt River Project introduced a demand charge as a standard feature of the rate for all residential customers with distributed generation in 2015 (Salt River Project, 2016). Residential demand charge proposals have also recently been made in Arizona, California, Illinois, Kansas, Nevada, Oklahoma, and Wisconsin.

What is driving this interest in demand charges? One driver is growth in capacity-related costs. Since demand charges are designed to recover costs driven by peak demand, namely generation, transmission and/or distribution capacity, high growth in these costs relative to other costs is emphasizing the need for a demand-driven rate component.

According to the U.S. Energy Information Administration (EIA), T&D costs, which are largely driven by peak demand, will represent a growing share of total electricity costs in coming years. Between 2012 and 2020, the EIA projects that transmission costs will grow at an average annual real growth rate of 2.4%, distribution costs will grow at 1.5%, and generation capacity costs will row at 0.1%. At the same time, the share of variable costs (primarily fuel) in the total is shrinking.

Technological developments are also contributing to the trend toward demand charge offerings. By allowing a customer's electricity consumption to be measured over short time intervals, smart meters are enabling, for the first time, widespread and low-cost deployment of demand charges. In the U.S., more than 50 million homes now have smart meters (FERC, 2015).

Declining electricity sales, coupled with growth in peak demand, are also contributing to this trend. In particular, industry concerns about a "cost shift" associated with net energy metering are causing regulators to consider reforming rates that are largely flat and volumetric in nature.

The degree to which demand charges will ultimately be adopted is, of course, uncertain. A number of strong drivers are pushing rate design in that direction. Other considerations, whether technical, political, or economic in nature, will also prominently influence this trajectory. Among the many issues currently being debated about the merits of demand charges, one that commonly rises to the top of the list is the impact on customer bills.

2. The bill impacts of residential demand charges

Customer bills will be impacted whenever revenue-neutral[3] changes are made to a rate's design. Some bills will go up as a result of the change and others will go down. It is therefore important to understand the extent to which customer bills will be affected when introducing a demand charge. From a policy perspective, the bill impacts for low-income or otherwise "vulnerable" customers are often of particular interest, out of concern that electricity remains affordable for this customer segment. To understand how demand charges might impact customer bills, we estimated bills for a sample of customers under two revenue-neutral rates, one with a demand charge and one without, while distinguishing between low-income and non-low income customers in the sample.

[2] Throughout this article, "three-part rate" is used to refer to a rate that includes a demand charge. Typically, rates with a demand charge will also include two other "parts," a fixed monthly customer charge and a volumetric (cents/kWh) charge.

[3] Two rates are considered to be "revenue neutral" when they produce the same revenue for the rate class, absent any changes in electricity consumption patterns.

Table 1
Illustrative Two-Part and Three-Part Rates.

	Two-part rate	Three-part rate
Demand charge ($/kW-month)	None	$7.00
Volumetric charge ($/kWh)	$0.110	$0.068
Fixed charge ($/month)	$10.00	$10.00

Note: Rates shown are illustrative. Many alternative designs are possible.

2.1. Data and methodology

To analyze the impact of demand charges on residential electricity bills, we obtained load data for a sample of more than 2000 customers in Vermont.[4] The load is measured over 15-min increments and covers a full year, from Oct. 1, 2014, through Sept. 30, 2015. That time period was selected because it represented the most recent data available at the time of our analysis. After examining the data and dropping customers for whom we had incomplete information (e.g. missing load observations), 1107 customers remained in the dataset.[5]

The dataset also included an estimate of household income for each customer in the sample. Income estimates were presented in incremental ranges (e.g., $40,000 to $50,000 per year). We considered households below 150% of the federal poverty line to be "low-income customers" and those above this threshold to be "non-low-income customers."[6] With this definition, 122 customers, or 11% of the total sample, were considered to be low-income customers.

We established a "before and after" comparison using two revenue-neutral rates. The "before" case is an illustrative two-part rate consisting of a fixed monthly charge and a volumetric charge. The "after" case is a revenue-neutral three-part rate that includes a demand charge in addition to a fixed charge and a volumetric charge.[7] The rates are shown in Table 1. Bills were then calculated for each customer in the sample under both the two-part rate and the three-part rate, with the change in bill representing the impact of the demand charge on each customer.

Note that the demand charge in this illustrative rate is based on the customer's highest hour of average demand between the hours of 2 p.m. and 6 p.m. each month. We chose that window of time because it closely coincides with the timing of system peak demand in Vermont. As discussed above, system peak demand drives a significant portion of the investment in generation capacity and power grid infrastructure. In other words, the rate is

[4] The data was provided by Efficiency Vermont. To maintain confidentiality of customer data, all customer account numbers were replaced with random identifiers; other information that might be used to identify individual customers was stripped out of the dataset before it was provided to the authors.

[5] Specifically, there were customers for whom a significant portion of load observations registered as 0 kWh. It is possible that some customers have very low load or perhaps own vacation homes that remain unoccupied for a portion of the year. It is also possible that the 0 kWh observations represent the transition in a change of occupancy or are possibly reported in error. Given the uncertainty and to minimize the impact on the sample, we chose to restrict our dataset to accounts with no more than 5% of observations registered as 0 kWh. We also dropped customers for which we did not have data for all days of the year, income data, or household size data.

[6] The U.S. Census Bureau's formula for determining the poverty line is a function of income, household size and age of occupants. A description can be found here: https://www.census.gov/hhes/www/poverty/about/overview/measure.html.

[7] To establish the revenue-neutral three-part rate, we set the fixed monthly charge equal to that of the two-part rate and the demand charge was set at $7/kW-month, which is within the range of residential demand charges being offered by utilities around the U.S. (for a recent survey, see Hledik, 2015). We then set the volumetric rate such that it produced the same revenue as the two part rate for the sample of residential customers (including both low-income and non-low-income customers).

designed to closely align the prices with costs, with the demand charge collecting a portion of demand-driven capacity costs.[8]

It should be noted that there are many different ways to design a demand charge, each with advantages and disadvantages, and these alternative designs could potentially have significant impacts on the findings of this study. See the sidebar for further discussion of the various demand charge design options.

Sidebar: The many ways to design a demand charge

A common misperception about demand charges is that they are always calculated based on each individual customer's own maximum demand over the course of the billing cycle, typically a month. While that is certainly a rate design option that many utilities have utilized, it is one of only many options available. As interest in demand charges continues to grow, it is likely that a range of new rate structures will be considered. The following are options to consider when designing a demand charge.

Peak window of demand measurement. Demand could be measured based on the customer's maximum demand over the course of the month, or alternatively, as in the example in this study, it could be constrained to a window of peak hours of the day. If the latter option is chosen, the window should align with the timing of the system peak demand that drives the costs the utility is aiming to recover with the demand charge. Narrower windows are generally easier for customers to respond to with changes in their consumption behavior, but may reduce the likelihood of accurately capturing the system peak.

Interval of demand measurement. Demand is typically measured on a 15-min, 30-min, or 60-min interval, and it would be technically possible to measure it on a shorter or longer interval as well. Shorter intervals more precisely capture instantaneous demand while longer intervals are often perceived to be more customer-friendly by reducing variability in demand.

Coincidence with system peak. Maximum demand could be based on the customer's individual contribution to the system (net) peak, as measured during that hour of the year or, similarly, during peak hours on the few highest-demand days of the year. With day-ahead notification to customers informing them in advance of the likely timing of a system peak hour, this rate design would in some ways resemble critical peak pricing.

Average of top demand hours. Maximum demand could be measured as the average of the customer's highest 5 or 10 demand readings each month, for example. This would avoid the perception that customers are "penalized" for an unexpected, isolated spike in demand.

Demand "ratchet." Some rate designs include a "ratchet" in which a customer's demand measurement is set during the months of the system peak (typically summer in the U.S.) and then applies for the rest of the year until the next peak demand season arrives. This improves bill stability and relates demand to the timing of the system peak but reduces the customer's ability to avoid the demand charge in non-peak months.

Tiered demand charge. The price in the demand charge can be a function of the customer's peak demand (e.g., with the first 3 kW billed at one price and remaining kW billed at a different price).

2.2. Findings of bill impact analysis

The three-part rate is revenue-neutral to the two-part rate, so the class average customer experiences no bill change. In other words, both the two-part rate and the three-part rate collect the exact same revenue from the class, assuming no change in electricity consumption patterns. An important question, though, is if the average low-income customer's bill change differs from that of the average non-low income customer. Our assessment of bill impacts found that there was not a statistically significant difference in average bill changes for low-income customers relative to non-low-income customers.[9] **On average, demand charges did not affect the bills of low-income customers differently than they affected the bills of non-low-income customers.**

This is an important finding. There is often concern that demand charges will penalize low-income customers. A prevailing belief is that low-income customers are lower-use customers on average and that, by virtue of this low usage, their bills will increase with a demand charge. In fact, the results illustrate that it is not the customer's monthly consumption that determines the bill impact of a demand charge. Rather, it is the extent to which the customer's load profile is "peakier" or "flatter" than average.

At the same time, it is important to recognize that climate, sociodemographic characteristics, appliance mix, and other factors will vary significantly from one utility service territory to the next. These findings are not necessarily applicable to the rest of the U.S. Additionally, while the analysis is based on load data for more than 1000 customers, only 122 of these customers were identified as "low income." Future analysis could be extended with a larger sample to provide more precision in the results.

It is also critical to consider the *distribution* of bill impacts across customers. With changes in rate design, it is common for *average* bill impacts to be small, but with customers at the outer ends of the distribution – specifically, those customers with more extreme load shapes – experiencing significant changes in their bill. This was the case to some extent in our analysis. Fig. 1 illustrates the distribution of bill impacts across all customers in the sample, with each customer represented as a single data point. Customers on the left side of the chart are those experiencing annual bill savings and customers on the right are those experiencing a bill increase.

Most customers in the sample experience only a modest bill change. Some experience meaningful bill savings. However, a portion of customers experience bill increases, with approximately 10% of customers seeing a bill increase of at least 20%. Given that some low-income customers are among the subset of customers who could experience a bill increase under the new rate, if affordability of electricity is a concern then it may be desirable from a social policy perspective to find ways to provide protections for those customers (as discussed later in this article).

Due to the design of the three-part rate, those customers with "peaky" load profiles experience bill increases while those with "flat" load profiles experience bill decreases. A number of factors could contribute to a peaky load shape. For example, a customer with relatively low load but occasional peak period use of large, electricity-intensive appliances would have a peaky load shape. Homes that are occupied only sporadically (e.g., short-term rentals) could also have spikes in load over the course of the month. Conversely, homes that are occupied regularly or with electricity consumption that is not concentrated in the peak period

[8] The appropriate timing of the peak period depends on the nature of the costs that the demand charge is designed to recover. For instance, distribution costs are local in nature and would likely be driven by demand that is roughly coincident with the class peak. Generation and transmission costs are driven more by the system peak. We have chosen 2 p.m. to 6 p.m. to align with the system peak in this example, but alternatives designs are also relevant.

[9] A two-sided *t*-test with p-value of 0.05 was used to determine statistical significance. No statistically significant difference was found, indicating that the true difference between the entire population of low-income and non-low-income customers' bill savings is statistically indistinguishable from zero.

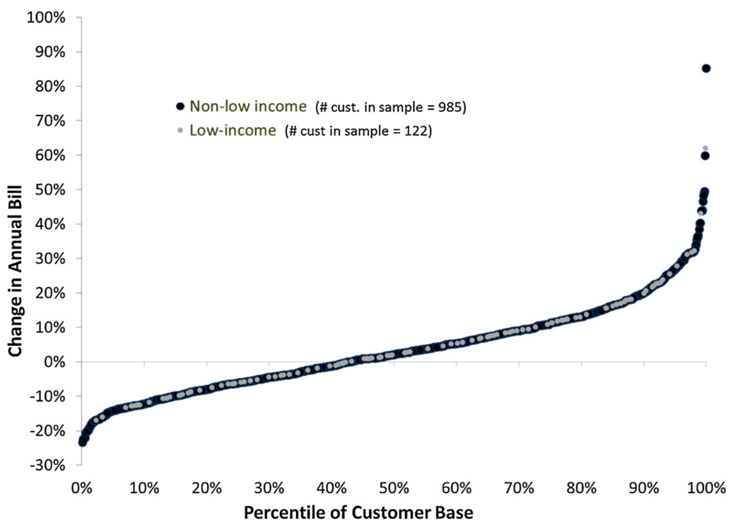

Fig. 1. Distribution of bill impacts across customers.
Notes:
1. Bill impacts shown are in the absence of price response. Accounting for price response could significantly increase bill savings.
2. While extreme outliers in the sample experience a bill increase in excess of 30%, the increase is relatively modest in absolute dollars, averaging $14.25/month across those customers.

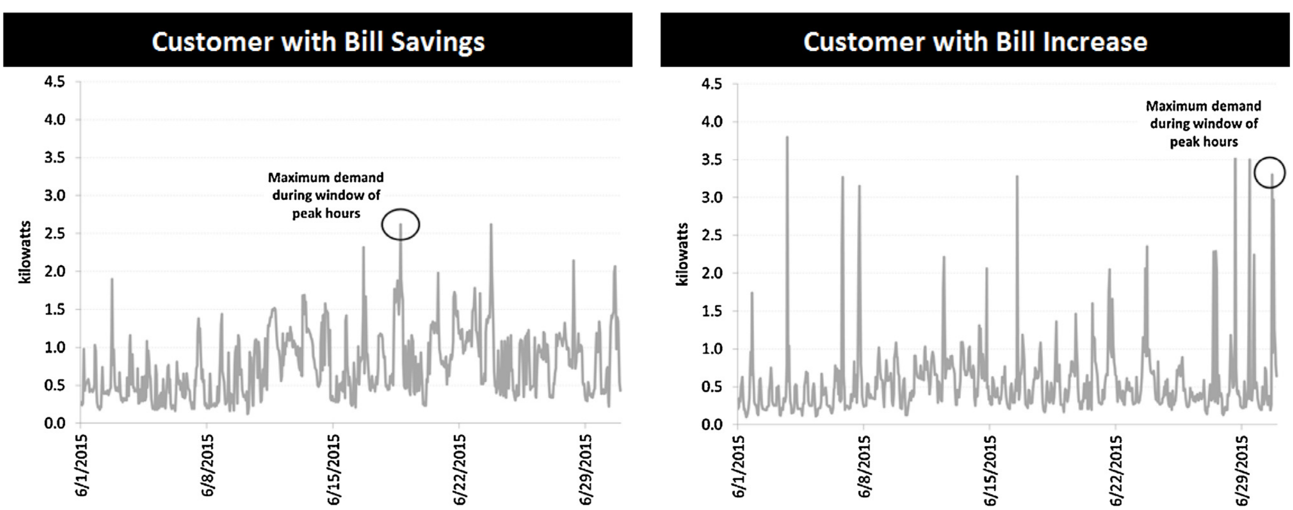

Fig. 2. Load profiles for two prototypical customers, June 2015.

hours of 2–6 p.m. could see bill decreases under the three-part rate. These are just a few of the many factors that drive a customer's load shape.

Fig. 2 illustrates the load profiles of two prototypical customers in the Vermont data. The customer on the left experienced bill savings (−11.0%, $7.92/month) on the three-part rate and the customer on the right experienced a bill increase (+12.9%, $8.92/month). The customers are in the bottom and top quartiles of the distribution of bill impacts shown above in Fig. 2, respectively. Average hourly consumption is shown for the month of June 2015. The hour of the customer's maximum monthly demand is highlighted on the chart. While the customers have roughly the same average monthly consumption over the course of the year (between 500 and 600 kWh/month, similar to the statewide average), it is the differences in their consumption patterns that drive the changes in their bills under the three-part rate.[10]

The changes in customer bills represent the removal of a cross-subsidy that existed under the two-part rate. Customers with flat load profiles, which are less burdensome to the power system, were previously subsidizing customers with peaky load profiles, which are more expensive to serve. The introduction of a demand

[10] It is worth noting that the average residential customer in Vermont consumes significantly less electricity than the national average, which is around 900 kWh/month. This is driven in part by lower market penetration of central air-conditioning in Vermont, and highlights the value of conducting similar analysis in additional jurisdictions.

charge addresses this cross-subsidy and improves fairness and equity in the rate's design. However, from a policy perspective, there may be interest in mitigating the most extreme bill impacts, particularly for those customers experiencing a significant bill increase. Several rate transition strategies can be utilized to this effect.

In addition to changes in the bill amount, it is also possible that introducing a demand charge could result in changes in bill volatility. A potential concern cited by some industry stakeholders about demand charges is that customers could accidentally and unknowingly create a sudden spike in demand during just one or two hours due to an infrequent event, such as hosting a party. The perception is that this could lead to unpredictable, spiky bills relative to the two-part rate.

To understand the impact of demand charges on bill volatility, we calculated the standard deviation of each customer's monthly bill over the course of the year under both the two-part rate and the three-part rate.[11] **We found that a majority (61%) of customers would experience a *decrease* in monthly bill volatility under the three-part rate.** For the remaining 39% of customers who experience an increase in bill volatility, roughly one-fifth would see a lower average bill, presumably an acceptable tradeoff for at least a portion of those customers. Overall, the change in bill volatility does not appear to be a particularly problematic issue for most customers, though it will be important from a policy perspective to be aware of the relatively small portion of customers at the extreme end of the distribution who are likely to experience a substantial change in the stability of their bill.

The bill impacts discussed thus far assume no change in electricity consumption patterns when customers enroll in the new rate. Ultimately, a change in rate structure is likely to lead to price response from customers.[12] The response could be in the form of behavioral change, with customers reducing their demand by turning off lights in unoccupied rooms or staggering the use of key appliances, for instance. Or the response could be enabled by new technology that automates those load reductions. One such emerging energy technology that is potentially a very good fit for demand charges is distributed energy storage.

3. Demand charges and energy storage

Demand charges provide customers with a new opportunity to manage their electricity bills by reducing their peak demand. It will be particularly important to consider demand management options for those customers who will experience a bill increase under the new rate design. Distributed energy storage is potentially a good "fit" for demand charges from this perspective, as it can help customers reduce their electricity demand at times when it would otherwise be high. With battery storage, for instance, the battery could be charged during hours when demand is low and discharged during hours when demand is high. Similarly, electric water heaters could be used as a form of thermal energy storage, consuming electricity to fully heat the water in the tank during nighttime hours (typically low-load hours) so that additional water heating is not needed during the day (typically higher-load hours) (Hledik et al., 2016). Air-conditioners could be used in a similar manner, pre-cooling the home before peak hours in order to reduce electricity needs during those hours.

The extent to which distributed energy storage could reduce the demand charge portion of a customer's bill, though, is a complex question. The answer depends on the operational capabilities of the technology, such as its storage capability and discharge rate. It also depends on the load shape of the customer. To develop a preliminary understanding of the relationship between demand charges and distributed energy storage, we analyzed the extent to which battery storage could reduce the bills of customers on a demand charge.

3.1. Data and methodology

For this analysis, we assume that a home battery can store 7 kWh of energy and discharge electricity at a maximum rate of 3.3 kWh/h. We also assume an efficiency factor of 92%, meaning that there is 8% energy loss associated with fully charging and discharging the battery. While a customer could install multiple batteries to increase this capacity, we have assumed a single battery for each customer in the Vermont sample. We have not attempted to "optimize" the sizing of the battery for each home, though that would be a valuable area of further research.

The design of the demand charge could significantly influence the impact of battery storage on customer bills. In this analysis, we used the three-part rate described in Section 3.1 of this article. That rate measured the customer's demand as the average over a 60-min interval. It is possible that measuring demand over a shorter interval could lead to significant differences in bill savings opportunities with battery storage, since the battery can be charged and discharged quickly.

The sophistication with which the battery is operated is also a critical assumption. We analyzed two different operational strategies as rough boundaries on the possible range of charging approaches. Recall that, in this study, we are analyzing rates in which demand is measured during the peak period hours of 2 p.m. to 6 p.m. In the "**Simple Charging"** strategy, the battery is assumed to fully charge outside of that peak period window and discharge at a constant rate that exactly depletes its stored energy over the four-hour peak period. This is repeated on a daily basis. This is a "simple" strategy in that it assumes no ability to predict when the highest demand hours are likely to occur. Rather, the battery is discharged to reduce demand by the same amount during all peak hours of each day.

The second approach is the "**Predictive Charging"** strategy. With this strategy, the battery also is assumed to fully charge during off-peak hours. During the peak period, however, the battery discharges at its maximum capacity on those hours when the customer's demand is highest. In other words, we assume that it is possible to predict when those highest demand hours are likely to occur, and that the energy from the battery is discharged at the highest rate possible during those hours to maximize the demand reduction. Given the specific technical characteristics of the battery we are modeling, this means that the battery fully discharges at a rate of 3.3 kWh/h for the two highest-load hours and a rate of 0.4 kWh/h in the third-highest hour, at which point it has fully discharged. The battery is charged and discharged on a daily basis.

Fig. 3 illustrates the impact of these two charging strategies on the energy consumption patterns of one of the customers in the Vermont sample on a typical summer day. The left chart illustrates how the Simple Charging strategy provides a uniform load reduction across the entire peak period while the right chart illustrates more targeted and deeper demand reductions of the Predictive Charging strategy.

[11] "Standard deviation" is a measure that is used to quantify the amount of variation across a set of data points. A standard deviation close to 0 indicates that the data points tend to be very close to the mean of the set, while a high standard deviation indicates that the data points are spread out over a wider range of values.

[12] Over 40 pricing pilots have examined the impact of a change in rate structure on residential electricity consumption. For further discussion, see Faruqui and Sergici (2013).

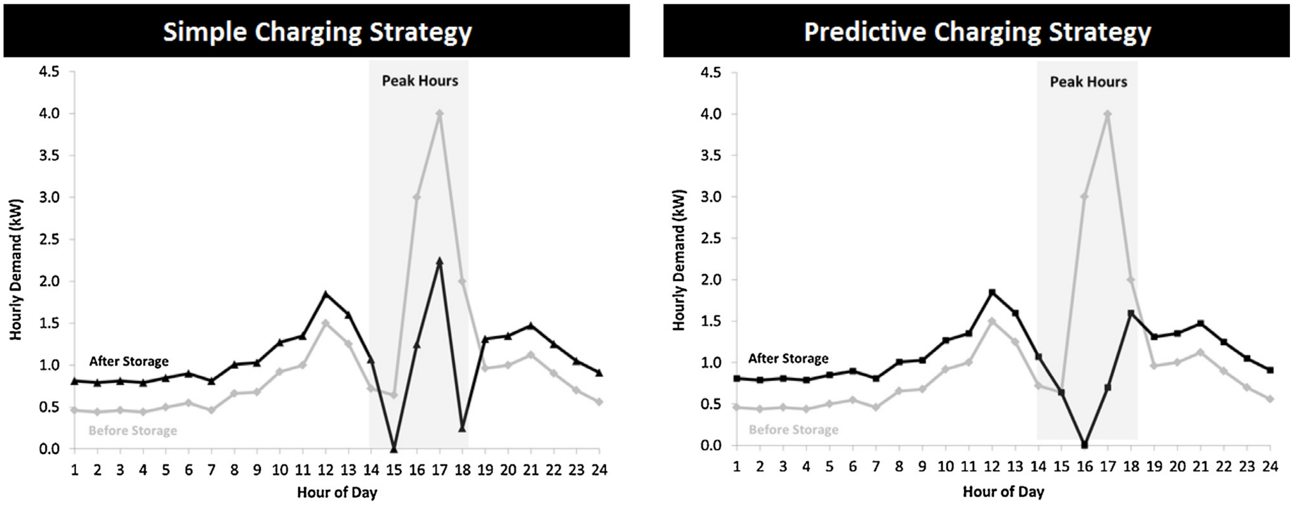

Fig. 3. Impact of charging strategies for one customer on illustrative day.

While the Predictive Charging strategy assumes some degree of foresight into the daily load pattern, it does not fully optimize the dispatch of the battery from a bill reduction standpoint. For instance, with perfect foresight, the battery would not be discharged on days with relatively low peak-period demand. This would avoid incurring the energy loss associated with the charge/discharge cycle on days when maximum demand is too low to set the demand charge. Similarly, on days with high demand during all hours of the peak period, a more optimal strategy would discharge the battery at a lower rate in order to be able to reduce demand during all of those hours. These issues are important considerations for designing battery dispatch algorithms and would be valuable for exploration in future research.

Ultimately, the charging strategies explored in this study represent only two out of many possible ways to dispatch batteries in response to demand charges. While the Predictive Charging strategy represents a more sophisticated approach to battery charging than the Simple Charging strategy, there are opportunities to improve upon these algorithms in practice. Our estimates of the potential bill savings are therefore conservative from a theoretical standpoint, but perhaps consistent with the some of the practical constraints that would exist around predicting demand and operating the battery.

3.2. Findings of battery storage analysis

By allowing customers to reduce their maximum demand, batteries can enable substantial bill savings under a three-part rate. But the magnitude of these savings varies across customers, charging strategies, and rate designs. Depending on the charging strategy, in our analysis, batteries led to bill savings on a three-part rate of anywhere from 13% to 28% on average across the sample of customers. Table 2 summarizes these average bill savings estimates.[13] Note that the changes in bill shown throughout this section of the article compare the customer's bill with and without storage under a three-part rate.

Of course, savings would be larger under a rate with a higher demand charge. Arizona Public Service, for instance, offers a rate with a 60-min demand charge that is \$13.50/kW in summer months and \$9.30/kW in the winter months (Arizona Public Service, 2016). Increasing the year-round demand charge in our analysis to \$11/kW (while decreasing the volumetric charge to maintain revenue neutrality) would lead to average annual bill savings of \$207 with the simple charging strategy and \$422 with the predictive charging strategy.

Further variation in bill savings is observed when looking at the savings of individual customers. Bill savings can range from more than half of the annual bill in some specific cases, to virtually zero in other cases. The latter instances are typically small customers with flat load profiles and modest demand savings that are overwhelmed by the efficiency loss associated with the battery's charging cycle. Fig. 4 illustrates the distribution of bill savings across all customers in the Vermont sample for both charging strategies.

Notably, those customers experiencing the largest bill *increases* when moving from two-part to three-part rates also tend to experience the largest bill *decreases* with battery storage under the three-part rate. In other words, the adoption of distributed energy storage (or other demand management technologies) could be an important mitigation strategy for customers with "spiky" demand profiles who would otherwise experience a bill increase in the transition to three-part rates. The relationship between bill impacts with a demand charge and bill savings with battery storage is illustrated in Fig. 5. The specific scenario illustrated in the figure is the Predictive Charging strategy.

Bill savings opportunities with distributed storage will vary depending on the characteristics of the regional energy market. Relative to much of the rest of the U.S., for example, households in Vermont have low electricity consumption and, as a result, lower bills than if consumption were closer to the national average. Bill savings could be substantially larger than those identified in this study in regions with higher consumption levels, peakier load profiles, and higher electricity costs.

It is also important to note that this study is not a cost-benefit analysis of storage. Simply put, the analysis does not account for the cost of the battery and its installation. Rather, the purpose of this study is to identify and quantify the potential opportunity for battery storage under a three-part rate offering. There is significant uncertainty around future battery costs. While the costs have declined significantly in recent years, whether or not they will

Table 2
Average annual bill savings due to battery storage under a three-part rate.

	Percentage	\$/Year
Simple Charging	13%	\$126
Predictive Charging	28%	\$263

[13] Values shown are the bill-weighted average monthly savings.

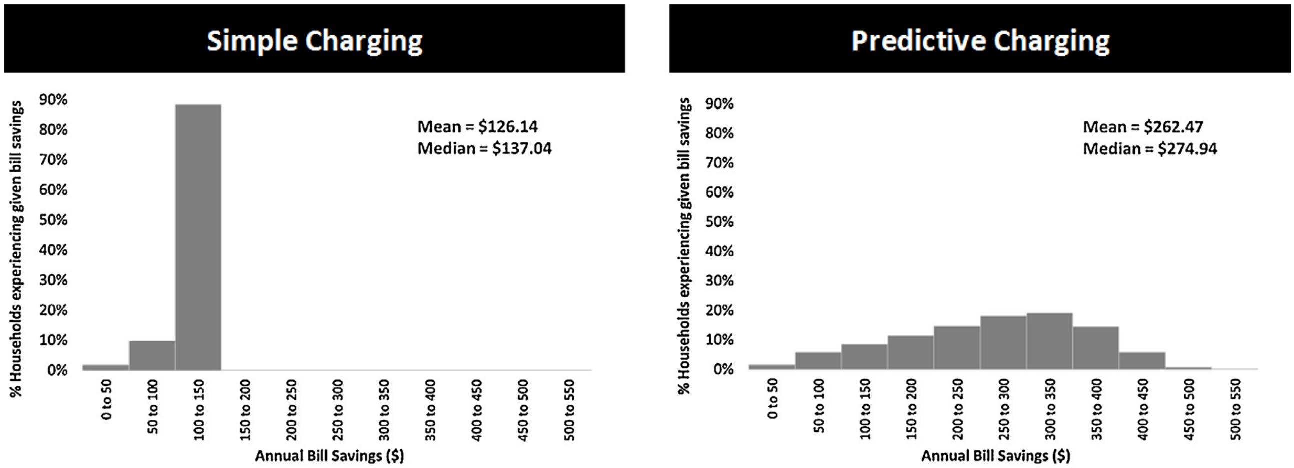

Fig. 4. Distribution of annual bill savings on three-part rate attributable to battery storage.

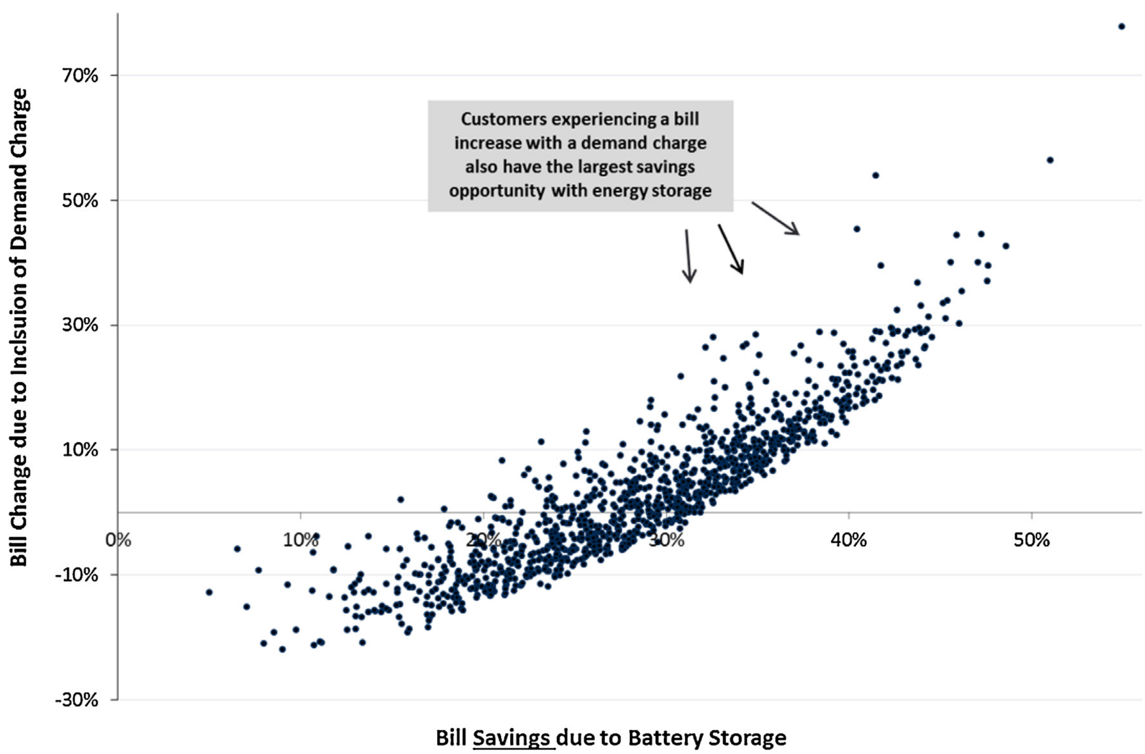

Fig. 5. Bill impact from demand charge vs. bill savings from battery storage.

reach the point of being broadly cost-effective for the mass market is yet to be determined. The findings of this study provide some guidance as to the magnitude of direct bill savings against which those evolving costs could be compared.[14]

4. Conclusions and policy considerations

This study has identified a number of key findings about the bill impacts of residential demand charges and the economics of distributed energy storage under a three-part rate. For the specific rate designs and Vermont customer load data considered, key findings include the following:

- On average, the impact of demand charges on low-income customer bills is no different than the impact on non-low-income customer bills.
- Across customers, some bills will decrease with a demand charge, and some will increase. In this study, most customers experienced only a modest bill change. A minority of customers in the sample – roughly 10% – experienced a bill increase of at least 20%. Some of these are low-income customers. New policies and strategies may be needed to provide protections or otherwise facilitate a smooth transition to the demand charge for these customers.

[14] There could be additional revenue streams for customers with battery storage beyond those captured through bill reductions. For example, by providing ancillary services to the wholesale market through a third party aggregator. PJM's "RegD" market is designed to allow for the provision of this type of service.

- A majority of customers experienced a reduction in monthly bill volatility with the introduction of a demand charge. Of the 39% of customers experiencing an increase in bill volatility, roughly one-fifth experience a reduction in their average bill.
- Demand charges can create substantial bill savings opportunities for customers with distributed energy storage. With the battery and three-part rate modeled in this study, depending on the operation of the battery, the average bill savings (not accounting for the cost of the device) range from 13% to 28%, or from approximately $126/year to $263/year. A higher demand charge could lead to significantly higher savings.
- The sophistication of the battery charging and discharging strategy can have a significant impact on the magnitude of bill savings. The design of the rate and the amount of revenue collected through the demand charge also have a significant impact on the bill savings opportunity.
- Customers experiencing the largest bill increases with the introduction of a demand charge also tend to have the largest bill savings opportunity with distributed energy storage or other demand management technologies. This is a particularly relevant finding in relation to concerns about the subset of customers who will experience bill increases with the introduction of a demand charge. While the economics of energy storage would need to be carefully considered, this highlights the role that such technology could play in mitigating the bill impacts of demand charges for these customers.

These findings, while preliminary in nature, suggest a number of policy options that should be considered as the national rollout of residential demand charges progresses. The applicability of these policy options will vary from one state to the next depending on the objectives goals of the local regulators, utilities, and their stakeholders.

4.1. Develop a rate transition strategy

In general, all customers will need to be educated about the new rate in order to improve their understanding of the rate's design as well as ways that they can manage demand and the impact on their bill. Beyond a broad educational outreach campaign, more targeted outreach may be useful for those specific customers who are likely to experience a bill increase on the new rate, particularly low-income or vulnerable customers. Those customers could be identified through bill impact analysis of utility load data, surveys, and other analyses based on locational sociodemographic data. In addition to educational initiatives, other elements of a rate transition plan might include a gradual phase-in of the demand charge, temporary bill protection, optional rate exemptions for a limited subset of the residential class who are considered low-income or vulnerable, or focus groups and surveys to determine the most effective ways to market the rate to customers. The design of a utility's rate transition strategy will depend on the specific circumstances of the utility, its customers, and stakeholders.

4.2. Consider a storage-specific demand rate

In jurisdictions where utilities are unlikely to offer demand charges to all customers, a demand charge may be an attractive feature of a rate that is designed specifically for customers with behind-the-meter energy storage. This is analogous to rates for owners of electric vehicles, which encourage their adoption and to provide a price signal that encourages off-peak charging. Similarly, if there is a desire to promote the adoption and efficient use of energy storage, a three-part energy storage rate could be developed, including a time-varying energy charge.

4.3. Promote demand management technologies

Given the potential benefits of energy storage under three-part rates, demand management technologies (batteries as well as other options) could be offered to customers as a tool for managing their electricity bill under the new rate design. The technology could be promoted through a rebate program, for example, or incorporated into a demand response program that provides bill discounts for participation.

4.4. Pilot demand charges with and without storage

Research on the impact of demand charges on customer consumption patterns is fairly limited and it is important that the industry learn more about how customers will respond to these rates.[15] The impact of the new rates should be tested through pricing pilots that are designed specifically to measure customer response to the new rates as well as satisfaction with the rate offering. The pilots could test the impact of behavioral response as well as the incremental impact of technology such as storage in enabling greater demand reductions.

4.5. Analyze the extent to which demand reductions will translate into cost savings

Reductions in peak demand have been shown to result in significant value in the form of avoided or deferred capital investment in new generation capacity, transmission and distribution system upgrades, and/or avoided peak energy costs (Faruqui et al., 2007). A well-designed three-part rate will provide a cost-based price signal that encourages reductions in demand at times when they are most valuable to the system. These demand reductions can translate not only into bill savings for participants, but also into reductions in utility costs.

4.6. Develop predictive algorithms for battery operation under a three-part rate

The sophistication of the battery charging/discharging strategy has a significant impact on the bill savings that can be achieved under a three-part rate. Research to develop predictive algorithms for discharging batteries would help to optimize the dispatch of the battery not only during times of high demand but also in response to other prices, such as energy and ancillary services prices. This would maximize bill savings opportunities for the customer as well as reduce system costs.

4.7. Explore findings in other regions and with alternative rate designs

Lastly, the methodological framework established in this study should be extended to other regions, rate designs, and emerging energy technology options. Given national interest in both demand charges and energy storage, it will be important to understand how these findings vary across these factors.

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[15] For a summary of pilots that have analyzed customer response to demand charges, see Hledik (2014).

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Ryan Hledik is a Principal in The Brattle Group's San Francisco and London offices. He specializes in the economics of policies and technologies that are focused on the energy consumer. Mr. Hledik holds a Master's Degree in Management Science and Engineering from Stanford University, with a concentration in Energy Economics and Policy, and a Bachelor's Degree in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. He can be reached at ryan.hledik@brattle.com.

Gus Greenstein is a Research Analyst in The Brattle Group's San Francisco office. His research has focused on the impacts of electricity rate reform and the economics of distributed generation technologies. Mr. Greenstein holds a Bachelor's Degree in Environmental Studies from Amherst College and will begin a Masters in Development Studies at Oxford University in Fall 2016.