Electricity as a Service: Cost Causation-based Utility Rate Model in the Future Distribution Grid

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ABSTRACT

Distribution grids across the world are undergoing profound changes due to advances in energy technologies. Electrification of the transportation sector and the integration of Distributed Energy Resources (DERs) such as photo-voltaic panels and energy storage devices has gained substantial momentum, especially at the edge of the grid. However, the massive transformation in the technological aspects of the grid could directly conflict with existing utility business models and tariff structures applied to retail customers. This paper proposes a restructured business model where the implementation of these grid-edge technologies is aligned with the interest of all stakeholders involved in the electricity ecosystem. This envisons a shift from treating electricity as a commodity where the users are charged based on their volumetric consumption, to treating it as a service provided to the end-user by the utility company based on the principle of cost-causation. The proposed rate structure considers the impact of individual customers on the distribution grid by calculating metrics that contribute directly to the costs incurred by the utility companies, namely magnitude and variability of the demand.

1. Introduction

 Distributed energy resources (DERs) have been integrated to the electric grid edge at an accelerated pace over the past decade. The levelized costs of photo-voltaic (PV) panels and energy storage have dropped significantly and are projected to continue this trend [11]. Behind-The-Meter (BTM) technologies are estimated to make up over 50% of the US energy storage market by 2021, with the deployed energy storage expected to reach 2 GW by then [21].

Despite the fact that end-use demand is projected to increase in the next few decades both in the residential and commercial sectors, there is a significant projected reduction in energy intensity [14]. Further, projections indicate that the growth rate of electricity sales will be diminished due to the significant increase in generation from rooftop PV systems, from both residential and commercial buildings [28]. The adoption of Electric Vehicles (EVs) is also on the rise, with the number of EVs on the road in the US reaching 1.1 million by the end of 2018 [16]. With increased installation of these technologies many consumers are turning into prosumers, thus eroding the revenue stream of the utilities [18].

The rise in DER penetration in markets around the globe makes the following question extremely relevant - are the existing utility business models poised to handle the accelerated pace of DER deployment at the grid edge? This paper addresses customer rate models of distribution utility companies i.e. how they recover their costs from customers. Distribution utilities need to be compensated for their investments and the grid maintenance costs they incur to ensure reliable power supply to all customers. Their compensation is akin to a toll fee for using the distribution utility’s grid infrastructure.

The existing transmission and distribution utility (TDU) charges are fashioned as a combination of a small fixed charge, coupled with a larger volumetric c/kWh charge - the dotted line in Fig. 1 represents the cost curve to consumers of this rate structure [24]. Clearly, the revenue earned by utilities is directly proportional to the volume of electricity in kWh that is consumed by the end-users. This rate structure incentivizes utilities to maximize sales and makes them dependent on the volumetric charge for the bulk of their revenue [9]. With the increased deployment of grid-edge DERs the current rate design could be insufficient since it does not fully account for the rising fixed costs faced by the utilities [15].

Grid-edge DERs pose a threat to the revenue stream of utility companies in a few different ways. Firstly, the increase in solar PV penetration directly results in reduction of kWh demand from the grid. This reduces the customer’s utility bill, even though the utility offers the service of access to the grid at all times, which the PV customer will require when the sun goes down. Secondly, the expansion of participation in net metering has resulted in utilities providing financial compensation for electricity injections from PV to the grid [20]. Costello [6] argues that there are a number of issues with net metering, including that it is inefficient and an unfair cross-subsidy.

The increased deployment of Advanced Metering Infrastructure (AMI) technologies provides an enabling platform for retail rate innovations that could improve upon the current volumetric rate structure. There has been a number of case studies devoted to examining the effect of high DER penetration on regulatory, technological and economic aspects in the distribution grid. The resulting need for utilities to update their business models, and a rebalancing of costs on the electricity value chain
from the grid side to behind the meter has been discussed in [29] and [27] respectively. Baak [1] and Pelegry [23] explore the regulatory framework in different parts of the world, and the restructuring that may be required to enable an accelerated transformation towards grid modernization, while Gellings [12] argues that the existing regulatory measures may be adequate to accommodate even a transformed future. Laws et al. [19] indicates that residential PV penetration could reach a substantial number over the next decade. But, they argue that utilities have ample time to change their business model in order to avoid the death spiral. Darghouth et al. [7] shows how various rate design choices can impact the long term cumulative distributed PV deployment.

Burger and Luke [5] provides a comprehensive review of the various business models that exist for various categories of DER technologies. Bird et al. [4] provides an analysis of how different rate structures, namely fixed charges, minimum bills and higher demand rates impact the bills of residential customers in a number of states across the US. Baatz [2] provides a summary of a number of recent studies on various rate structures such as Time-of-Use (TOU), Critical Peak Pricing (CPP) etc. Schwartz [26] presents the pros and cons of various rate designs. Namely, raising fixed charges for all customers may disproportionately impact low-income customers. Minimum bills do not necessarily fix the utility revenue problem. Demand charges are usually applied to the customer’s peak demand regardless of whether it is coincident with distribution system demand. Revesz and Unel [25] reviews the net-metering related tariff changes in a number of jurisdictions in the US. They also argue for an approach that values clean distributed energy for its social impacts such as environmental benefits and reduced losses. Faruqui et al. [9] suggests transitioning residential customers to three-part rates, comprising of a monthly fixed charge, a volumetric charge, and a demand charge. In [13] an analysis of BTM storage adoption under a storage-friendly rate is presented.

In [3], a Distribution Network Use-of-System (DNUsoS) charge has been proposed, which aids in accurate recovery of distribution utility costs, by capturing the contribution of each user on the network to the system’s costs. This paper applies a similar line of thought, by billing the customers based on their individual contributions to system costs.

In view of the above, the key contributions of this paper are as follows:

- A methodology to quantify the impact of individual customers on the grid based on demand magnitude and variability metrics has been proposed
- A novel utility rate mechanism has been formulated, which calculates TDU charges for individual customers based on the cost causation principle
- Numerical case studies have been developed using data from real residential customers with a high penetration of EVs and Solar PVs, to simulate the effect of the proposed rate mechanism

The rest of the paper is organized as follows: Section 2 highlights the deficiencies in the existing utility business model, and describes the design details and mathematical formulation of the proposed billing mechanism. Section 3 is a critical comparison of the existing and proposed new utility business models, supported by a case study using real residential customer data. Section 4 summarizes the key learnings and the most significant policy implications of the proposed utility business model.

2. Methodology and Data

2.1. Present Utility Business Model

The proposed TDU charge features the introduction of a single grid-access fee, which would completely replace the traditional â€œsmall fixed + large volumetricâ€ structure of utility pricing. The uniqueness of this idea lies in how these grid-access fees would be customer-specific; calculated for each customer by taking into account some key parameters that define the impact of said customer to the grid. This impact is quantified through a combination of weighting factors called Grid Impact Factors.

This concept is analogous to an insurance rate model or a credit score, where each customer’s rate/credit limit is considered to accurately reflect the risk level taken up by the insurance company / bank by entering into business with said customer. An example of providing appropriate incentives in electricity wholesale markets is FERC Order 755 [10]. Prior to this Order, most ISO markets in the US had a single capacity payment for regulation. Regulation payments were not tied to resource performance. As a result of this rule a two-part payment was enacted, which added a mileage based component that accounts for the performance of the resource, in addition to the capacity based payment.
As is evident from Fig. 1, the utility company does not have revenue assurance i.e. they have to hope that consumers use more kWh, thus driving up their revenue. However, under the proposed approach the utility has a steady and assured income from each consumer via the fixed Grid Access Fees. In the figure, Customer 2 has a lower grid impact than Customer 1, and thus is charged a lower Grid Access Fee.

2.2. Metrics causing Distribution Grid Investments

In the context of a distribution grid, the installed capacity of the system is a key parameter - it determines how much load can be served. Depending on changing load patterns this limit also dictates the need for capital investment. System capacity requirements are directly dependent on the system Peak Demand to be supplied to the customers. Thus, the "Peak Demand Time Slots" are a critical time for the system. To account for this, a Demand Magnitude Impact Factor \( W \) is introduced, that measures the demand impact weight of each home during the peak demand time slots.

\[
W_i = \frac{\text{Total Demand of Home } i \text{ during Peak Slots}}{\text{Total Demand of Home } i}
\]

Another key concern for the distribution grid is the health of the existing infrastructure. This directly impacts the capital investment and maintenance costs that the utility incurs. The health of grid infrastructure is correlated to its load-variation and the fluctuations in demand. These fluctuations are measured using the Demand Variability Impact Factor \( V \), during the peak variability time slots of each home.

\[
V_i = \frac{\text{Total Variability of Home } i \text{ during Peak Slots}}{\text{Total Variability of Home } i}
\]

2.3. Peak Indicator Functions

With the objective of making the rate structure as flexible and general as possible, the idea of Peak Indicator Functions for Demand and Variability has been introduced. These take as inputs the present system conditions, the peak threshold for the system conditions, and a strictness parameter \( k \), to deliver an indication of whether the system condition at that time \( t \) is considered to be a peak slot or not. When \( k \) is very small, the Peak is considered based on a very strict cut-off, whereas if \( k \) is larger, the function also begins to consider those time slots where System Demand \( (S') \) is almost equal to the peak threshold, thus reducing the importance and emphasis placed on an inherently arbitrary definition of peak threshold.

Distribution grids have diverse load profiles, even between different feeders within the same utility service territory. The proposed mechanism provides the grid operator the option to use their engineering judgment to select peak thresholds and \( k \) values that are best suited for their system conditions.

Peak Indicator Functions have been defined for Peak Demand Magnitude (\( S \)) and Peak Demand Variability (\( V \)) as \( \mu \) and \( \lambda \) respectively. These are described below.

2.3.1. Peak Demand Magnitude Indicator \( \mu \)

This function is designed similar to a logistic function, and is centered around the System Peak Threshold value \( S_\text{PeakTh} \). \( S_\text{PeakTh} \) is calculated based on a percentile value that can be set by the distribution grid operator. If the peak threshold percentage is set as 15%, then \( S_\text{PeakTh} = S_\text{15th} \) percentile of System load duration curve. This means that a given time slot \( t \) is defined as a peak demand time slot when \( S' \geq S_\text{PeakTh} \). In essence, this function returns 1 if it is a peak slot, and 0 if not. For a given time \( t \), \( \mu \) is described as follows:

\[
\mu^i = \frac{1}{1 + e^{-\left(S' - S_\text{PeakTh}\right)}}
\]

2.3.2. Peak Demand Variability Indicator \( \lambda \)

The Variability indicator has the additional unique property of being unbounded, thus it not only indicates that a given slot is a peak slot, but it also captures how big the peak is, i.e. it quantifies the peak.

Similar to \( S_\text{PeakTh} \), \( \beta_\text{PeakTh} \) is calculated based on a percentile value that can be set by the distribution grid operator. \( A \) given time slot \( t \) is defined as a peak variability time slot when \( \beta' \geq \beta_\text{PeakTh} \). For a given time \( t \), \( \lambda \) is defined as follows:

\[
\lambda^i = k \ln(1 + e^{-\left(\frac{\beta' - \beta_\text{PeakTh}}{k}\right)})
\]

2.4. Calculating the Grid Impact Factors \( W \) and \( V \)

Let \( X_i^t \) = Demand of user \( i \) at time \( t \)
\[
dX_i^t = \text{Change in Demand of user } i \text{ between time } t 	ext{ and } t - 1
\]

i.e. \( dX_i^t = X_i^t - X_i^{t-1} \)
2.4.1. Element-Wise Multiplication

\[
W'_i = X'_i \cdot \mu'_i \\
V'_i = dX'_i \cdot \lambda'_i \\
W_i = \sum_i W'_i \\
V_i = \sum_i V'_i 
\]  
(3)

2.4.2. Matrix Multiplication

\[
W_{N \times 1} = X_{N \times T} \cdot \mu_{T \times 1} \\
V_{N \times 1} = dX_{N \times (T-1)} \cdot \lambda_{(T-1) \times 1} 
\]  
(4)

2.4.3. Relative Weight (% Allocation) for each Home \(i\)

\[
W_{\text{share} \ i} = \frac{W_i}{\sum_{j=1}^{N} W_j} \\
V_{\text{share} \ i} = \frac{V_i}{\sum_{j=1}^{N} V_j} 
\]  
(5)

2.5. Calculating the Final Bills

Let \(B_{i \text{old}}^{\text{total}}\) → Total Bill of home \(i\) calculated in the current method, and \(B_{i \text{new}}^{\text{total}}\) → Total Bill of home \(i\) calculated in the proposed method.

To calculate bills for each home under the current mechanism, we consider a standard volumetric rate formula for TDU Charges defined below (5 c/per kWh) \((X'_i > 0)\):

\[
B_i^{\text{old}} = $0.05 \times X'_i 
\]  
(6)

In case a home generates more than it consumes at any point in time, i.e. \(X'_i < 0\), the excess electricity is sold back to the grid at a discounted rate of 2 c/per kWh (Net Metering).

\[
B_i^{\text{old}} = -$0.02 \times X'_i 
\]  
(7)

So, the total TDU Charges in the current mechanism for the full 2 year period is calculated as follows.

\[
B_{i \text{old}}^{\text{total}} = \sum_i (B_i^{\text{old}}) 
\]  
(8)

In the proposed rate calculation mechanism, customers are charged a fixed monthly bill based on their Grid Impact Factors. This fixed charge is calculated by starting from the total target revenue for the utility company. This is the reverse approach of the existing mechanism, thus a stark difference from the procedure followed in the current scheme, where the individual customer’s rate is based on a fixed formula, and an aggregation of all customers’ payments gives the total revenue for the utility company.

It is assumed that the $/kWh rate is derived from the total target revenue of the system, which is obtained as a result of the current rate case process. This rate case is determined by a joint effort between the utility and regulator, to ensure accuracy and fairness to utility and customer alike.

For simplicity, the work in this paper operates under the assumption that the total target revenue is calculated for the full period of assessment - in the case study described in the paper, this period of assessment is 2 years. Further, to make a fair and direct comparison of the current and proposed mechanisms, this total target revenue for the utility company has been fixed as the \(B_{i \text{old}}^{\text{total}}\) value, i.e.,

\[
\sum_{i=1}^{N} B_{i \text{old}}^{\text{total}} = \sum_{i=1}^{N} B_{i \text{new}}^{\text{total}} 
\]  
(9)

This essentially results in a redistribution of the same final cost among the customers. This is a fair assumption to make because the total target revenue for the current mechanism is calculated through the rate case process, which is assumed to be an accurate reflection of system costs.

Since the new mechanism has to account for two contributing grid impact factors \(W\) and \(V\), the importance of these respective weighting factors are determined by the allocation percentage parameters \(\Pi_W\) and \(\Pi_V\) (also determined by the utility and regulator), defined as follows:

\[\Pi_W = \% \text{ Allocation of Total Target Revenue for } W\]
\[\Pi_V = \% \text{ Allocation of Total Target Revenue for } V\]

And so, finally, the total bill for each home \(i\) as per the new scheme is calculated as a linear combination of the weighting factors scaled with their respective allocation percentage parameters, as follows:

\[
B_{i \text{new}}^{\text{total}} = W_{\text{share} \ i} \times \Pi_W + V_{\text{share} \ i} \times \Pi_V 
\]  
(10)

2.6. Data and Case Study System Description

The data used for the results discussed in Section 3 is the instantaneous kW demand for 200 residential customers, measured at a resolution of 1-minute. The dataset spanning a period of two years (from 01-01-2016 to 12-31-2017) was obtained from Pecan Street Dataport [22].

3. Results and Discussion

To thoroughly examine the effects of the new billing mechanism, we calculate the bills for each home in a system of 200 residential demand profiles, with 25% penetration of EVs and PVs each, i.e. 50 EV homes and 50 PV homes among the 200 total homes.

For the purpose of this example, we set the \(S_{\text{PeakTh}}\) and \(\beta_{\text{PeakTh}}\) at the 75th percentile of total system demand and total system variability respectively. Also, the % Allocations of Total Target Revenue \(\Pi_W\) and \(\Pi_V\) are set as 75% and 25% respectively.

3.1. Comparing the Performance of Two Homes in the Proposed Mechanism

To illustrate the effects of the proposed scheme, we examine two homes which have a similar bill in the current scheme but a significant difference in bills in the proposed scheme.

In Fig. 4 (top), the system demand curve has been plotted along with the Peak Threshold line (red), indicating which intervals are considered to be peak time slots. Fig. 4 (bottom) depicts the individual demand of the higher impact and
lower impact homes during the system peak time slots, and is assumed to be zero for non-peak time slots.

Despite having a few spikes of demand, the demand of Home 1 during the peak time slots is, for the most part, less than that of Home 2. Furthermore, Home 2 has a negative demand for several time periods each day i.e. it is generating more power than it consumes, indicating that it is a solar PV home. The fact that this home is a higher impact home can be explained by the benefit given to solar PV homes in the current scheme due to net metering. In the proposed scheme, such demand variability is penalized through the $V$ parameter.

### 3.2. Comparing the Current and Proposed Billing Mechanisms

Fig. 5 describes the effect of the proposed billing mechanism for each subset of homes. This effect is quantified by evaluating the percentage change between the proposed bill and the current bill, i.e. $B_{\text{new}}^i - B_{\text{old}}^i$ for each home. The distribution of this range has been plotted, categorized based on the type of home: EV Homes, PV Homes, and non-DER Homes.

In the case of EV homes, most homes have a negative % change of $B_{\text{new}}^i - B_{\text{old}}^i$. This means that almost all homes have a lower bill in the proposed mechanism than they do in the current mechanism. As a result, it seems that the proposed billing mechanism is favorable for EVs. This follows...
intuition, because in the current billing mechanism, all that matters for billing is how much kWh volume is consumed by the home. Whereas in the proposed billing algorithm, the impact of the user is calculated during the peak time slots of demand, where the distribution system is under the most stress. Thus, under the proposed billing mechanism, there is great potential for smart scheduling of EV charging during the non-peak periods, which could lead to significant savings for those homes. As a result, the interests of both the distribution utility and the user are aligned.

When we observe the trend for PV homes, most homes have a positive change of \( B_{\text{new}}^{\text{total}} - B_{\text{old}}^{\text{total}} \), which means that almost all PV homes have a significant increase in their bill when evaluated under the proposed mechanism. While this observation seems to suggest that the proposed mechanism is unfavorable to PV homes, it can be argued that the proposed mechanism is capturing the true costs of PV that were previously (unfairly) being borne by non-PV homes. Despite the fact that the kWh volume of consumption for PV homes is less, the sudden ramping of PV during the late evening causes significant strain on the distribution grid. This aspect is captured in the new billing scheme through the Variability impact factor \( V \).

Let us now consider the case of non-DER homes. Most homes have a negative percentage change value for \( B_{\text{new}}^{\text{total}} - B_{\text{old}}^{\text{total}} \). More specifically, of the 100 non-DER homes, almost 90 have a negative change (0-20% reduction in bill). This indicates that most non-DER homes are being benefited by the proposed billing mechanism. This addresses one of the key drawbacks of the current utility billing scheme, where in many cases, costs incurred by the utilities in their PV-incentive programs such as net metering or other subsidies would be recovered from the non-PV customers via increase in the fixed charges. With the proposed mechanism, the trend of penalizing non-PV customers is reversed, bringing the distribution of bills back to balance.

3.3. The Effect of DER Penetration on Bills Calculated under the Proposed Mechanism

Fig. 6 describes the effect of penetration of individual DERs (EV and PV) on each subset of homes. In the default system, there is a DER penetration of 25% EV and 25% PV (50 homes each). In the system without EV, the DER penetration is 0% EV (0 homes) and 25% PV (50 homes). Similarly in the system without PV, the DER penetration is 25% EV (50 EV homes) and 0% PV (0 PV Homes). In the system without DERs, the DER penetration is 0%, i.e. 0% EV and 0% PV. The left figure compares the bills of the EV Homes calculated in the default system vs the system without EVs. The middle figure compares bills of PV homes calculated in the default system vs the system without PV generation. The right figure shows the effect on bills of non-DER homes due to DER penetration in the system, by comparing the bills calculated in the default system vs the system with 0% DER penetration.

When considering the effect of EV penetration on EV homes, it is observed that most homes have a positive change between with and without EV cases, thus following the expected trend of having higher electricity bills due to the presence of an EV.

With PV however, the story is different. Some PV homes seem to benefit with the introduction of PV (around 30 homes), but the rest have a higher bill with the introduction of PV. One factor could be explained by the variability index \( V \) accounting for 25% of the total revenue, and that the PV homes have the highest variability impact factors. Another issue could be that PVs are pulling down the system conditions below peak threshold when the sun is shining, and shifting peak slots to different times. This leads to a very interesting thought: the application of solar + storage technology combined with smart scheduling for maximizing usage during system non-peak conditions could be the optimal strategy in the proposed billing scheme. This has been explored in the case study discussed in Section 3.4.

Looking at the effect of DER penetration on non-DER homes, it is noted that every single non-DER home has seen a reduction in their electric bills due to the penetration of...
DER. While this seems like the proposed mechanism rewards customers for not investing in DER, it is more accurate to view this as evidence that a fair cost recovery from DER homes is happening because of DER homes having an increase in their grid impact, due to the penetration of DERs.

3.4. Effect of Battery Storage on Bills calculated under the Proposed Mechanism

Fig. 7 shows the effect of penetration of battery storage in the system on the bills calculated under the proposed rate mechanism. In this case study, half of the PV homes (25 out of 50) are given a battery storage unit, that operates under a brute force algorithm, charging during non-peak hours (1AM - 3AM), and discharging during typical peak hours (5PM - 7PM), with a rate of 2 kW for both charge and discharge cycles. Essentially, this is meant to reduce impact on grid by discharging during peak time slots, and charging during non-peak time slots.

Fig. 7 (top-right) shows that every single ‘PV+battery’ home has experienced a reduction in bill due to the introduction of battery storage. This reduction has been observed despite the fact that a brute force charging-discharging schedule was implemented. This result could be further improved if the battery storage devices are operated under a smart-scheduling algorithm, that not only reduces impact during peak time slots, but also counteracts spikes in variability of the system, thus earning rewards for positive contributions to grid conditions.

The other 3 sub-figures in Fig. 7 show the effects of the introduction of battery systems in 25 PV homes on the other categories of homes. Homes in all of these categories see minor increases in their bills, so it could be argued that the proposed mechanism provides the most rewards for customers having PV + battery storage, who are more likely to be richer customers, at the expense of non-DER customers, who may be less affluent and cannot afford PVs and battery storage. However, when comparing the bills of these non-DER customers under the proposed and current schemes, it is clear that these homes will still be better off than they are under the current scheme.

3.5. Pros and Cons of the Proposed Mechanism

3.5.1. Pros

Revenue Decoupling The mechanism introduced in this work effectively decouples utility revenue and customer bills from volumetric consumption. This is important to the long-term stability of utility revenues, since due to the growing penetration of DERs, volumetric charge based revenue could decline in the future.

Recovers Utility Costs Accurately and Effectively The proposed mechanism is more representative of the true costs inflicted upon the distribution grid by the customers, due to the usage of kW rather than kWh as a defining metric. The major driver for investment costs in equipment is the consumer demand during peak periods. Thus, the proposed approach provides better alignment between the revenue and costs as compared to the volumetric charge. The introduction of ‘Variability’ is also a novel approach. The variable nature of renewable resources adversely impacts the efficient operation of the grid and as such should be accounted for in the cost recovery mechanism.

Utility Revenue Targets are Assured to Be Met There is a key and prominent distinction between the proposed mechanism and the current model - rather than expecting a total revenue for the utility depending on several variables, the
The proposed mechanism offers the utility the opportunity to ensure a stable and assured revenue. This is because the total target revenue is first set, and then the proposed mechanism allocates the costs to all customers appropriately. Another advantage is that this form of rate-making could require less frequent rate cases, which is a time-consuming and expensive process.

**Reduces Unfair Cross-Subsidy** Both the current volumetric charge and the net-metering policies result in utilities over-recovering costs from non-PV customers while under-recovering them from PV customers. Further, there is a high likelihood that non-PV customers fall in the low-income category, while PV customer fall in the high-income category. Thus the proposed mechanism mitigates against the existing unfair and regressive cross-subsidy. Further, the proposed approach is consistent for all types of DERs. This is important to incentivize technologies such as energy storage.

**Retains Efficiency Incentive** Under the current volumetric mechanism increasing efficiency reduces electricity sales and therefore profits [17]. The proposed billing mechanism retains the incentive for the utility to be efficient. Since the total revenue target is controlled under this structure, the utility is incentivized to take action to improve system efficiency so as to get higher profits. Regulators could also include explicit performance bonuses for utilities improving their efficiency.

3.5.2. Cons

**Peak Threshold Calculation Unfair to Solar PV?** As mentioned earlier, the introduction of PV could cause the total system demand to go below the peak threshold in some time slots, thus converting those time slots from peak slots to non-peak slots. However, this also shifts the peak slots to a different time, because of the fact that peak slots are defined on a percentile basis, rather than absolute. There will always be a top $x\%$ set of values; it does not matter whether that range is small or large. As a result, the new system peak time slots would be those times when perhaps the sun does not shine. The appliance usage of a PV home is not offset when the sun is not shining, therefore these new shifted peak slots could be when the PV homes stop generating, and demand power from the grid, thus contributing to increase in the system demand. These slots are now the peak slots, and PV homes along with all other homes contribute to their $W$ and $V$ impact factors significantly during this time. Thus, it could lead to the situation where non-PV homes get away with ‘bad’ usage patterns when the sun is shining, because PV homes are generating enough power to reduce the stress on the system below the system peak threshold. Essentially, some non-PV homes escape penalization due to their behavior being covered or compensated for by the PV homes.

This problem could be easily dealt with when rolling out the proposed mechanism in practice: peak thresholds could potentially be selected by distribution grid operators based on distribution feeder capacity, for the feeders on which this algorithm is being implemented. This would make the thresholds absolute, rather than relative.

**Solar PV ancillary benefits** It could be argued that Solar PV is not being rewarded for the various benefits it brings to the grid or indeed its societal benefit in terms of reducing pollution. Distributed PV systems likely provide ancillary benefits such as reducing distribution system losses by generating close to the point of consumption, and in the future also might offer frequency and voltage support services through the use of smart inverters [8].

**Rate simplicity** Clarity and simplicity is a consideration for rate design. In this respect the volumetric rate has an advantage since customers have become accustomed to it. On the other hand it could be argued that customers are also familiar with the concept of credit scores, and being subject to different interest rates relative to other customers, based on their individual risk to the lender.

3.6. Policy Implications

The current volumetric rate structure has some clear drawbacks, the first being that the utility is not assured of sufficient revenues, and the second that there is effectively an unfair cross-subsidy from non-PV customers to PV customers. Since with declining revenues the utility would be forced to raise the rates for everyone. The proposed approach provides long-term stability to the utility. PV customers could face higher bills, but this could be considered appropriate given that the energy they contribute may not be coincident with peak demand, which is a large driver of distribution system costs. Moreover, if such customers also had optimally operating storage, their bills could be reduced.

With the introduction of metrics such as peak thresholds and % Allocation, the utility has far greater flexibility to modify the billing mechanism based on the true costs they incur, customized for their system conditions.

Regulators should be careful not to favor a particular technology and rate designs should be based on the true value of energy provided by DER assets.

4. Concluding Remarks

With the increasing penetration of DER technologies, utilities are likely to face challenges associated with the current volumetric rate design. Regulators should consider alternative rate designs that are better aligned with the cost-causation principle.

This paper introduces an algorithm to calculate a fixed, customer-specific grid access fee, based on metrics that contribute directly to the true costs incurred by the distribution utility in providing electric power to their customers. As a result, the volumetric throughput incentive is eliminated, thus aligning the interests of both the distribution utility as well as the end-users towards a future distribution grid with higher DER penetration. This has been accomplished through a shift in philosophy, from treating electricity as a commodity to *Electricity as a Service*. 

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Future work will have to answer some key questions: further insight needs to be gained on how to calculate the actual Total Target Revenue, such that it recovers the costs incurred by utilities under different system conditions. The effect of smart-scheduling algorithms that respond to real-time signals of system performance needs to be tested. Applying this on solar+storage could be transformative, and thus needs to be explored. Further, this holds great potential for customer aggregation, where groups of customers form such that these customers’ consumption patterns could be negatively correlated with each other. This could reduce the group impact on the grid, thus reducing their bill as part of a group, compared to their bill when considered as individual customers. Smart-scheduling and real-time adaptive consumption patterns could be leveraged in such aggregation mechanisms to negate the spikes and troughs of other customers in the group.

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