



Editorial

Dispelling the myths of residential rate reform: Why an evolving grid requires a modern approach to residential electricity pricing



1. Introduction

One cannot read the trade press these days without coming across articles discussing advancements in behind-the-meter energy technology and its associated impact on the U.S. electric grid. Rooftop solar is the technology leading the way, with battery storage, electric vehicles, load control devices, and other innovations looming close on the horizon. As customers adopt these technologies, they change the way that they use the electric grid. Where once customers took power only from the grid, they now use the grid both to import and export electricity, resulting in a two-way flow of power: from the utility to the customer and the customer to the utility. These changes require electric utilities to play a different role in the generation and delivery of electricity than they historically have. Reliability will always be a paramount consideration for America's technology-savvy and energy-dependent population. Ensuring reliability in an era of two-way power flows requires power companies to evolve the grid into an integrating platform that invites the adoption of customer-sided technologies while maintaining the fundamental physics that keeps the system functional. The utility's role as a network integrator and system balancer will become increasingly important. And as the utility's functions evolve, so must its pricing structure.

2. What are the alternatives to the traditional kilowatt-hour unit of pricing?

Electricity costs are driven by various factors. Costs that vary with a customer's kilowatt-hour (kWh) energy consumption, such as fuel, are appropriately priced based on the kWh unit of measurement. However, most utility infrastructure costs do not vary with the amount of energy consumed. Rather, infrastructure is sized to serve peak consumption, which is the maximum amount of energy used over a short period of time, such as a 15-min period or a single hour, versus the energy consumed over an entire monthly billing period. These costs, which include such items as power plants, transmission and distribution lines and poles, are often described as being driven by demand or capacity and are measured on a maximum kW basis. Other costs of providing electric service are based on the needs of a single customer, such as a billing meter and service connection, and do not vary with either energy or demand. These are described as "per customer" costs, which are also fixed.

For the most part, the rate designs used for the various customer classes have depended upon the available metering technology. Before the advent of cost-effective meters, customers were charged a flat fee or by the number of light bulbs installed at a residence. Over time, meters were developed that were capable of measuring both demand and energy. Demand meters were more costly and typically did not make sense for residential customers who were considered reasonably homogenous as a class; that is, most residential customers used energy the same way and were viewed as lacking the disparities in system usage that would justify a more complex rate design and the corresponding cost of the more expensive metering infrastructure.¹ For that reason, traditional residential electric rates were based on the billing measurements that could be taken by cost-justified energy meters: the customer and kWh components. While easy to understand, an energy-only rate design does not reflect the difference in cost among customers who have different levels of demand. Two customers may have the same energy usage, but their usage patterns may be such that one requires more generation, transmission, and distribution infrastructure than the other. An energy-only rate undercharges the more demand-intensive customer, and overcharges the customer who uses the grid more efficiently.

As it always will, technology has evolved and the metering economics has now changed. Advanced metering can be implemented at a reasonable cost for residential customers, thereby making three-part residential rates a viable option. Three-part rate designs reduce the billing disparity caused by energy-only rates and are increasingly appropriate as the once-homogenous residential class diversifies with respect to how they use electricity, given such factors as the adoption of distributed generation and other customer-sided energy technology.

Recognizing the policy benefit of three-part residential rates, utilities throughout the country are seeking to reform residential rate designs to include a demand component. Some utilities in the U.S., including Arizona Public Service Company (APS), have had an optional residential demand rate for decades, and the approach is gaining traction. The gravitation to demand-based rates has

¹ Commercial customers, on the other hand, did use the system differently, thereby justifying a more sophisticated rates design and the corresponding investment in demand meters. For decades, commercial customers' electric bills have been based on kW, kWh, and per-customer charges.

Misunderstanding the derivation and implementation of a residential demand-based rate

In the November 2015 Issue of *The Electricity Journal*, Scott J. Rubin's article entitled "Moving Toward Demand-Based Residential Rates" evaluated several rate design options and hypothesized that a rate with seasonal consumption charges would make significant progress toward a more efficient rate design (as measured by the correlation between costs and revenues). Mr. Rubin also concluded that a demand rate based on monthly billed demand was inefficient at aligning a utility's cost drivers with revenue collection.

Mr. Rubin's analysis of a demand charge assumes that a demand charge is theoretically set by the single peak hour. That, however, is a gross misunderstanding of the derivation and implementation of a residential demand-based rate (at least here at Arizona Public Service). Mr. Rubin's flawed assumptions led him to the flawed conclusion that demand rates, and the revenues they will produce, are not well correlated to the cost of providing service.

Mr. Rubin may also misunderstand the cost allocation process and proof of revenue concept that ensures the test-year costs and revenues are in alignment.

APS allocates its cost of providing service for generation, transmission, and distribution based on the appropriate cost drivers. Rates are then developed, using a proof of revenue and monthly billing information to recover the allocated cost. Empirically, the very nature of this process creates a very high correlation between the cost of service study and the rates that customers pay.

A single demand does not drive all infrastructure costs; rather, those costs are driven by a series of demands that vary by the infrastructure category and likely time of day, month or year during which they are incurred (for example, generation and transmission costs for APS are driven by the summer peak season; substations and distribution primary costs are driven by class peaks and secondary distribution is driven by individual demands). The cost allocation process follows this complexity.

While these infrastructure costs are driven by various configurations of demand, they are not driven by a home's monthly kWh energy consumption. A TOU energy rate will not provide a higher correlation between costs and revenues. If the cost allocation is done properly (using the various demand cost drivers) and a valid proof of revenue is developed for the rate design, it is not possible for a TOU energy rate design to have a higher correlation than a demand rate design.

generated much conversation in the industry and conceptual arguments both for and against the rate design is now a common dialogue. This article uses real data and relies on the decades of experience that APS has with residential demand rates to debunk the myths associated with demand pricing and replace what have been hypothetical suppositions with reality.

3. APS: a case study in residential demand rates

APS first offered residential demand rates in 1981 and presently has over 117,000 residential customers voluntarily on a time-of-use (TOU) demand rate. APS also has more than 427,000 residential customers on a TOU energy rate. Given this long duration and significant adoption of both TOU energy and demand rates, APS has significant data that provides insight into the effectiveness of each approach in shaping a customer's energy usage. APS data shows that customers on TOU energy rates reduce their peak demand by

approximately 5% compared to customers on inclining block rates, primarily due to the enhanced focus on the on-peak pricing period. In addition, data shows that customers on a TOU demand rate have significant potential to further reduce their peak demand compared to those on a TOU energy rate.

APS has data from 977 customers on its system that took service under a TOU energy rate for the 2012 calendar year and then switched to a demand-based rate in 2013 and remained on a demand rate through 2014. That data evidences that customers respond to demand rates, reducing peak demand and saving money. Of those 977 customers, 60% saved an average of 12.5% on their peak demand in the summer peak season. And the most engaged customers (the top 5% savers) reduced their peak demand by approximately 39%. This results in savings that will add up and translate into real capacity deferrals and corresponding system savings – all from sending more precise price signals through rate design. Of those customers that did not actively respond to the price signals sent by the demand rate, 75% still actually saved money simply by subscribing to the three-part rate.

4. Using this data to debunk the myths about residential demand rates

Myth one: residential demand rates will allow the utility to collect for the same infrastructure twice and recover more revenue than authorized.

Reality: this myth reveals a fundamental misunderstanding about the ratemaking process. During rate proceedings, utilities are required to demonstrate a "proof of revenue" that shows the regulatory body charged with approving rates and tariffs that the proposed rate designs will collect the authorized amount of revenue – no more and no less. How costs are divided between customers is determined through a detailed process during which utilities allocate costs to the appropriate customer classes based on the demand, energy, and customer cost drivers in proportion to their use of infrastructure and energy. The allocated cost responsibility is then divided by the class billing determinants (actual demand, energy and customer information) to develop the specific rates. This allocation process and proof of revenue method ensures that rates do not over- or under-collect revenue. Indeed, commercial customers – typically the most sophisticated customers to participate in utility rate proceedings and actively engage in the proof of revenue and rate design process – have been on demand-based rates for decades. Had the design resulted in duplicative recovery, it would not have lasted long.

Myth two: customers cannot understand residential demand rates.

Reality: customers can learn to manage and understand rates. APS has 34 years of experience with residential demand rates and presently over 11% of APS's residential customers voluntarily subscribe to a three-part rate structure. The additional level of understanding can be communicated at a high level: put simply, do not turn on all of your electric-intensive appliances at the same time. Because APS measures demand for residential customers over a one-hour period of time and most appliances do not run continuously for an hour, there is some built-in forgiveness of a short-term overlap of multiple appliances. The demand reductions presented in the case study above validate that residential customers grasp and engage in the demand management concept, since there is a noticeable demand savings once a customer switches to a demand rate.

Further, approximately 65% of new customer growth for APS over the last five years has selected the residential demand rate, increasing from less than 90,000 customers in 2010 to over 117,000 customers today. Because APS is fully deployed with

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