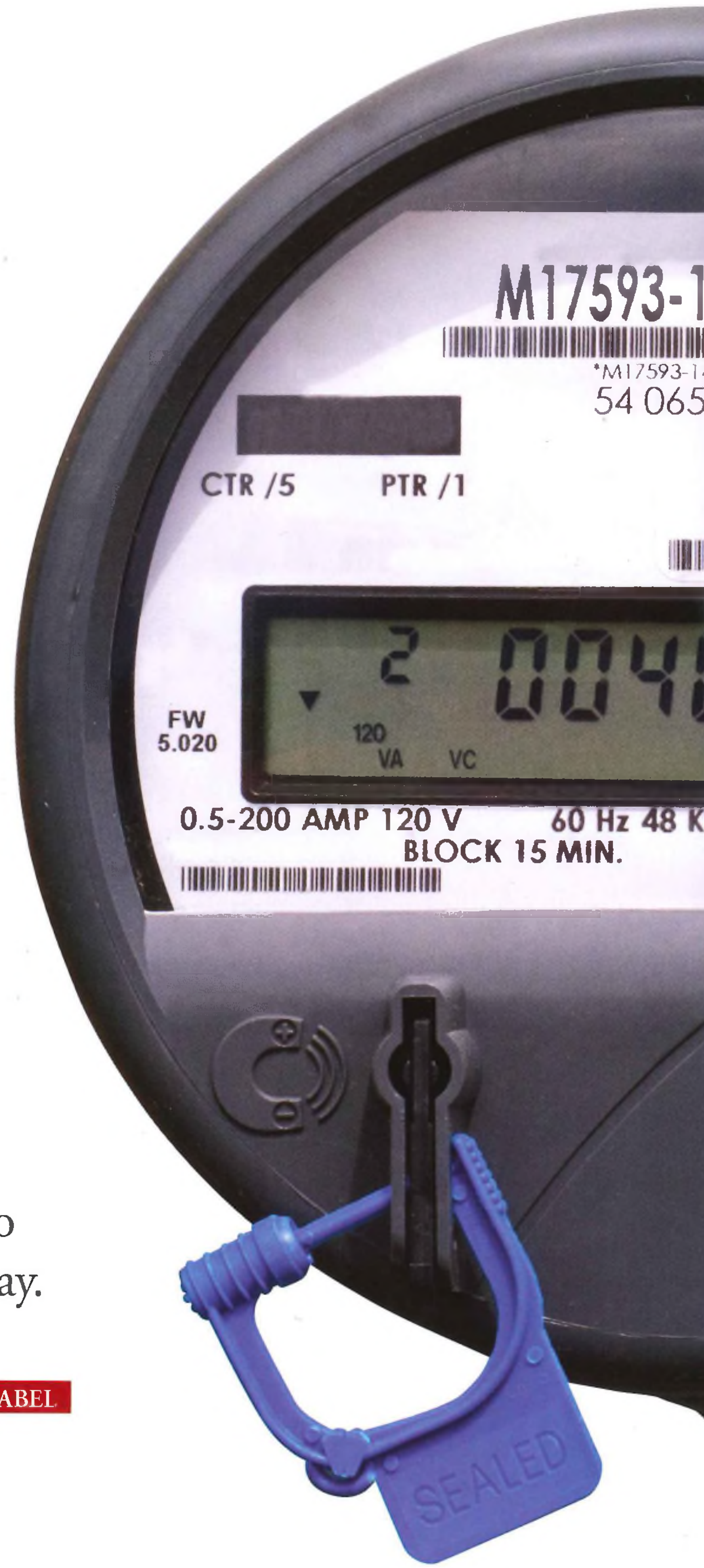
There and Back Again



Why a residential demand rate developed 40 years ago is increasingly relevant today.

BY LELAND SNOOK AND MEGHAN GRABEL

Picture the Arizona desert in the mid 1970s – hot, dry, and full of promise. With average summer temperatures exceeding 100 degrees in the Valley of the Sun, it is no wonder that centralized air conditioning would redefine lifestyles in the Grand Canyon State and prompt significant population growth.

Central AC worked wonders for the Arizona economy and, from the local utility's perspective, changed how residential electric customers used energy. In 1970, Arizona Public Service Company (APS) saw its residential customers demanding 426 megawatts (MW) of capacity at the coincident peak. But with the proliferation of air conditioning, that number more than doubled to 992 MW by 1980. To meet that need, APS would have to add new generation and grid infrastructure to its system – incurring significant costs that ordinarily would be passed along to all grid users.

Enter Paul Hart, an executive with APS and a seasoned veteran of utility pricing puzzles. Hart understood that his customers had dramatically changed the nature of their energy use. Traditional utility pricing schemes would no longer ensure that customers installing central air would pay their fair share of costs. Nor would it send price signals to incent those same customers to manage their energy use and keep system costs down.

Traditional utility pricing was – and still is, for the most part – volumetric. That means that virtually all utility costs are recovered through a single per-unit price, based on kilowatt-hours (kWh). That kWh price recovers costs that change with the amount of energy consumed (such as fuel), along with fixed costs that do not (such as power plants and the electric lines and poles that the utility must have in place no matter how much or how little electricity its customers use). Volumetric energy pricing can recover fixed costs reasonably well when all residential customers have roughly the same electricity loads – when everyone wakes up, makes breakfast, leaves for work or school, comes home, and makes dinner, etc., at about the same time, and in the same manner. But when a segment of customers are doing all of these things *and* running central AC to cool a desert home, the volumetric charge will no longer fairly allocate the higher amount of fixed costs now required to build the extra grid infrastructure needed to serve them. Instead, well-accepted principles of rate design suggest that rates should be designed to achieve equity – a certain fairness in how costs are allocated – so that like-situated customers are treated equally.[1] Volumetric energy pricing often falls short of that goal.

Hart ruminated on Arizona's changing scene: Why not design a rate that allocates the higher system cost to customers based on their actual energy demand? Not the total electrons consumed over elapsed time, but the higher system-wide capacity needed at peak periods to serve air conditioning use. After all, the commercial and industrial customers that drove peak demand were already familiar with rates that relied on system demand as a price signal. Why not apply the same notion for residential customers?

Rate design should set energy apart from grid services, so customers pay for what they use.

Hart's innovation won out. But lifestyles never stand still: nor does utility regulation. Central air conditioning eventually became ubiquitous, with regulators finding ways ensure fairness in rate design.

Today, however, we face a second shock to the system. It's a revolution in residential lifestyle that promises even greater disruption than that caused by central air conditioning. Can regulators learn from the 1970s, drawing on past experience to craft a new rate design to even out this new incongruity – the upheaval we know as rooftop solar?

Then: Air Conditioning

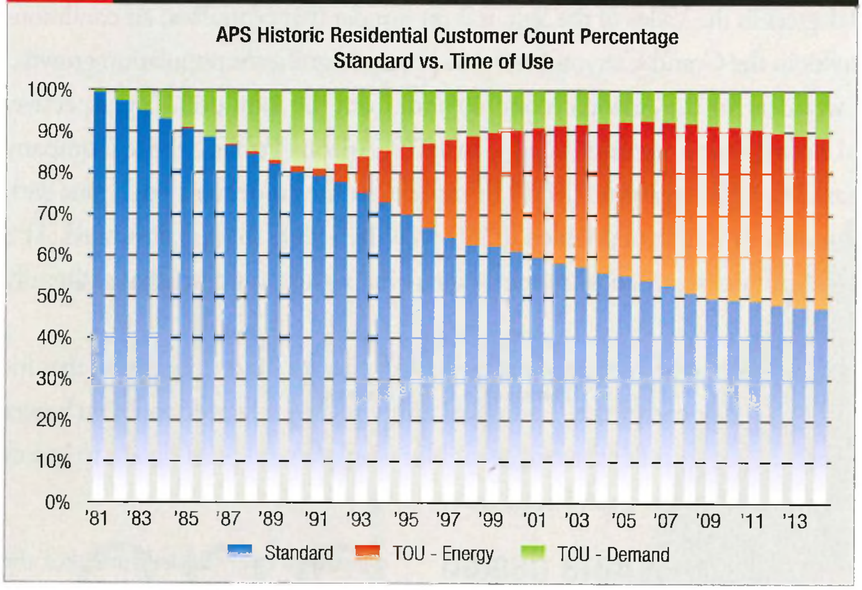
The concept of applying a demand charge to residential customers was novel at first. There was no guarantee the Arizona Corporation Commission (ACC) would approve it. Regardless, Hart went to work on a plan to design a rate structure that would encourage demand management, while ensuring fairness to customers who already had central air conditioning at their homes.

In August of 1977, APS filed a new proposed rate for residential customers, known as "Electric Capacity – 1." This rate featured three components: 1) a basic service charge, which recovered costs associated with metering, meter-reading, billing and the service line to the home; 2) a kWh energy charge that recovered fuel costs, as well as a small portion of the generation, transmission

1. *Principles of Public Utility Rates*, Professor James C. Bonbright, Columbia University Press (1961) at 291.

Leland Snook is director of rates and rate strategy for Arizona Public Service Co. Attorney **Meghan Grabel** is a partner in the administrative law group of the Phoenix law firm Osborn Maledon, and served previously as associate general counsel (regulatory) for Arizona Public Service.

FIG. 1 APS RESIDENTIAL RATES



and distribution-related fixed infrastructure costs; and 3) a demand charge that recovered fixed infrastructure costs based on the number of kW used during the highest hour of demand in the customer's billing period. APS proposed to make this new residential demand rate mandatory for all new homes built in its service territory with central air conditioning, but only voluntary for any existing customers with central AC. By "grandfathering" any existing customers with central air, APS hoped to make the transition more palatable to the general public and the state's elected Commissioners. It seemed like a fair approach.

Yet change is never easy. The commissioners at the ACC deferred a decision on the proposal, stating that it required further consideration and research. APS then tried again three years later, in July of 1980, requesting a non-timed residential demand rate as part of a then-pending rate case. This time, the utility prevailed. The order[2] adopting the rate stated that a residential rate based primarily on each customer's electric energy consumption "ignores the fact that the cost of providing electric service is increasingly a function [of] the demand for electricity place[d] on the system rather than the total power consumed."[3] The Commission recognized further that including a demand component in the residential customers bills would provide an incentive to customers to manage their electric load "in a manner that can result in lower electric bills for the individual customers." "Equally important," the Commission reasoned, was the likely effect on overall system-wide requirements. If customers were to modify their behavior in response to the price signals sent by a demand charge, the utility could see a reduction in peak demand which, according to the ACC, "can have the effect of reducing the need for expensive additional generating facilities."[4]

For those reasons, the Commission approved the residential demand rate as mandatory for all new customers with central air conditioning and optional for existing customers.

Two years after APS implemented its first non-timed residential demand rate, the Commission approved two time-of-use (TOU) rates: one with a demand charge and one without. In the early years of the TOU offering, more customers selected the demand version. Over time, as the use of air conditioning became commonplace and customers migrated once again to generally amorphous usage patterns, the initial rationale for a demand-based rate for customers with air conditioning subsided and the energy-only TOU rate became the dominant customer choice.

In general, time-of-use rates have been met with great success in Arizona. Today, over 50 percent of APS's residential customers have opted for a TOU rate in one form or another. *Figure 1* illustrates customer adoption of energy and demand-based TOU pricing structures over time, in contrast to a standard inclining-block rate plan.

Utility pricing is still largely volumetric, reflecting kWh, not system demand.

Now: Rooftop Solar

Undoubtedly, air conditioning transformed the desert's energy landscape. Arizona has grown tremendously since 1980. APS's customer base has grown by approximately 290 percent, and residential demand today has increased 370 percent from 1980. But that was then, this is now.

Similar to air conditioning at the tail of the last century, today's new technology innovations installed on the customer side of the electric meter have changed not only how people use electricity, but how they use the electric grid, making the residential demand rate a more important regulatory tool than ever.

Historically, power flow moved in one direction, from the utility to customers. Since customers purchased all of their electric energy needs from the utility, a consumption-based rate was generally workable: when everyone buys all of their electricity needs from the utility, the difference between the energy product sold and the grid services provided remains generally unimportant. The utility can pro-rate the cost of the grid services

2. ACC Decision No. 51472, October 21, 1980.

3. See id. at Finding of Fact 1.

4. See id. at Finding of Fact 3.

into the energy product and come out even financially. Thus, while rates with a demand feature would more precisely assign cost responsibility to the cost causer, they were not essential to promote an economically efficient transaction.

Today, however, advancements in customer-sided technology, such as rooftop solar systems, have turned customers into what some in the industry are calling "prosumers" – individuals who both produce and consume energy.[5] As a result, the electric grid has evolved to a system of two-way power flow: customers take energy from the system at times, and send it back at others. Given this fundamental change in how the system operates, the difference between the energy product that the utility sells and the grid services it provides has become critical. Customers with behind-the-meter generation may not always rely on the utility for electricity supply, but they still will require grid services every hour of every day of the year. The intermittency of customer-sided distributed generation and the dynamic nature of two-directional power flow makes managing the electric system physics more challenging than ever for the utility. In many cases it requires additional operational attention and grid infrastructure support in order to keep the lights on and power quality high.

While the way customers use the energy product and grid services has changed, rate design generally has not. Rates are still based on the amount of electricity that customers purchase from the utility, with no consideration paid to the grid services that the utility provides. Most of what it takes today to provide reliable electric service to customers depends on utility infrastructure such as poles, wires, transformers and power plants. On the other hand, the bulk of a customer's electric bill reflects how much of the energy product they bought, which is generally a function of the fuel cost to produce the energy.

Today, almost 70 percent of the costs to serve APS's residential customers are fixed infrastructure costs – the cost of its reliability service. Only about 30 percent of those costs are driven by the cost of generating energy. On the other hand, only 10 percent of a customer's bill pays for service-related fixed infrastructure. A full 90 percent of the bill is based on the amount of the energy product a customer purchases. Put another way, if a customer does not buy the utility's product, she doesn't pay for grid services – even though she continues to use them. See *Figure 2*.

FIG. 2 ENERGY USE VS. GRID SERVICES

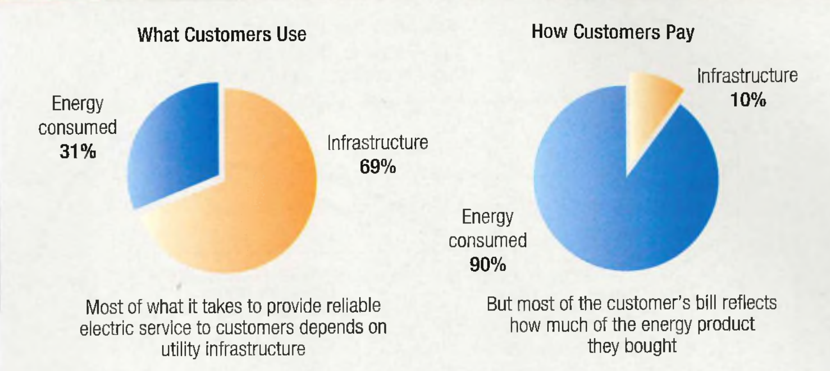
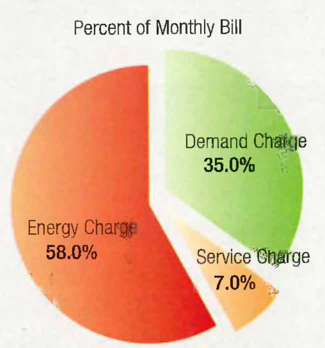


FIG. 3 DEMAND RATE: HOW IT WORKS



Service Charge ($ per Month)		
All Service Amps	$ 16.91	
Demand Charges ($ per kW) [1]		
Summer	$ 13.50	
Winter	$ 9.30	
Energy Charges ($ per kWh)		
	Peak [2]	Off Peak
Summer	0.08867	0.04417
Winter	0.05747	0.04107

1. Demand is based on the highest one-hour kW read during on-peak hours in a billing month.
2. On peak hours are 12 noon to 7 pm, excluding weekends and holidays.

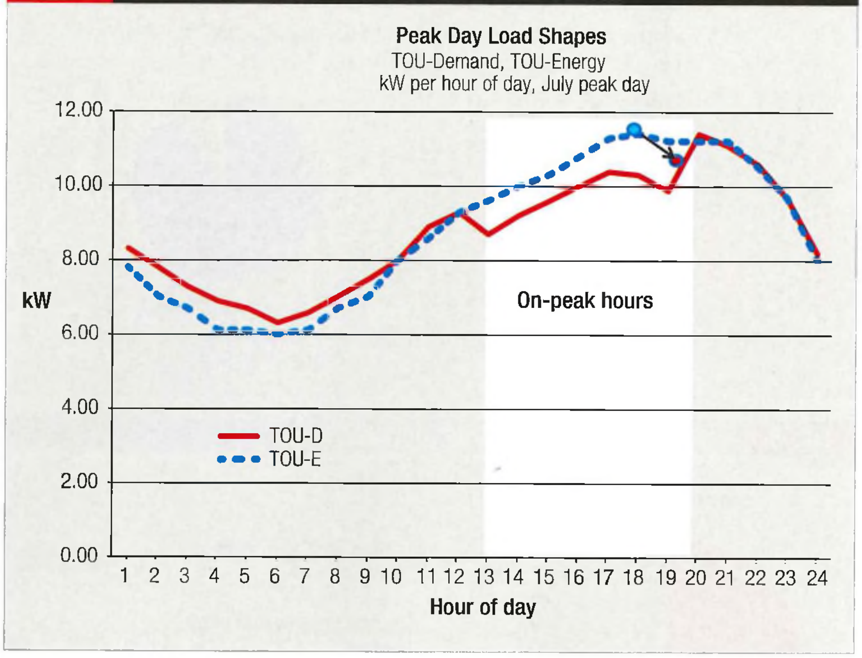
Our residential demand rate shows a higher load factor than our pure TOU tariff.

This misalignment between fixed costs and fixed charges, brought on by distributed generation, causes problems for customers and utilities alike, an issue that has been the subject of several regulatory decisions and industry publications.[6] The issue, however, is not one of intentional cost-avoidance. It is fundamentally a pricing problem. Utility rate design must evolve to reflect the distinction between the utility's energy product and grid services, so that customers pay for what they use.

5. *See, e.g.,* Hertzog, Christina, "What Is Prosumer Value to the Utilities?," March 3, 2014. Found at http://www.theenergycollective.com/christine-hertzog/2200061/what-prosumer-value-utilities.

6. *See, e.g.,* David B. Raskin, *The Regulatory Challenge of Distributed Generation*, 4 HARV. BUS. L. REV. ONLINE 38 (2013); Ashley Brown and Jillian Bunyan, *Valuation of Distributed Solar: A Qualitative View*, The Electricity Jounral, Vol. 27 (December 2014); Ryan Hledik, *Rediscovering Residential Demand Charges*, The Electricity Journal, Vol. 27 (July 2014).

FIG. 4 DEMAND RATE IMPROVES LOAD FACTOR



The demand rate concept has recently been approved by utility regulators in several states as an effective rate structure to meet those objectives in a manner that is fair to all customers and that achieves longer policy objectives.[7] At APS the almost four decades worth of experience with TOU and demand-based rates informs these discussions. Today, more than 110,000 APS customers are subscribed to the utility's residential demand rate. *Figure 3* shows the rate as currently designed.

As *Figure 3* shows, current residential demand rate at APS has a demand charge, depicted in green, which varies by summer and winter season. As it has for decades, the demand charge collects fixed infrastructure costs based on the highest integrated one-hour kW read taken during on-peak hours during the billing month. The rate also features a monthly service charge, which likewise collects fixed infrastructure costs. Collectively, these two components make up 42 percent of the average monthly bill. The remaining 58 percent of the bill is collected through an energy charge that varies both by season (summer and winter) and time of day. If fixed costs and fixed charges were perfectly aligned, the combination of the demand charge and basic service charge would make up about 70 percent of the bill, not 42 percent. Nevertheless, this design is markedly better than any of APS's consumption-based energy rates – TOU and non-TOU alike – in terms of recovering the cost of grid-related services fairly from all customers.

While this cost shift could be resolved by other types of rate designs (straight fixed/variable, for example), a key benefit of a demand rate is the price signal that it sends to customers and their resulting energy-demand behavior. Send the right price signal, as Hart foresaw 40 years ago, and customers will take measures to manage their load and improve their load factor. For example, as *Figure 4* depicts, APS demand-rate customers on average display a flatter usage pattern, which suggests closer management of peak demand. This conclusion is buttressed by other APS data showing, for example, that customers on a residential demand rate have a 37 percent load factor – a significant improvement over customers on a pure TOU rate, whose load factor runs only about 29 percent. Were all of APS's customers to respond to the price signals sent by a demand-based rate and improve their load factors respectively by almost 8-10 percent, the utility would see significant savings in system costs.

With the rise of rooftop solar, a demand rate is more important than ever.

In addition, customers on APS's residential demand rate exhibit a lower peak demand compared to both customers on an energy-only TOU rate and a standard inclining block rate. Customers on a demand-based TOU rate save from 11 percent to 21 percent of monthly peak demand compared to customers on the utility's inclining block rate, and shave peak demand by anywhere from 5-15 percent compared to customers on an energy-only TOU rate.

Another key benefit of the residential demand rate comes from the price signals it sends, encouraging innovation in customer-sided technologies. While an energy-only TOU rate can encourage customers to shift consumption to certain parts of the day over others, it does not encourage them to be more efficient, nor does it encourage behavior that will spur the development of load-control or other technologies that might lead to more efficient and cost-effective use of the electric system. Imagine the load management potential that accompanies more sophisticated technologies, such as "smart" thermostats, electric vehicles, and battery storage. And, like the APS rate, a residential demand rate can have a TOU component, encouraging both off-peak usage and better load management.

7. *See, e.g.*, **Arizona**: Salt River Project Standard Electric Price Plans https://www.srpnet.com/prices/priceprocess/pdfx/April2015RatebookPUBLISHED.pdf; **South Carolina**: Residential Net Billing Rate, South Carolina Public Service Authority, page 2, https://www.santeecooper.com/pdfs/rates/2014/rb-14.pdf., Accessed July 2015; **Wisconsin**: Wisconsin Electric Power Company, Customer Generating Systems – Net Metered (CGS NM) Less than 300KW https://www.we-energies.com/pdfs/etariffs/wisconsin/ewi_sheet2016-2018.pdf, accessed July 2015).