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Policy Brief

Retail Pricing to Support the 21st Century Distribution Grid

By Frank A. Wolak

As an increasing number of California households install solar panels, the current approach to retail electricity pricing makes it harder for the state's utilities to recover their costs. Unless policymakers change how they price grid-supplied electricity, a regulatory crisis where a declining number of less affluent customers will be asked to pay for a growing share of the costs is likely to occur.

The retail price a household pays for the last unit consumed of grid-supplied electricity is an important driver of the decision to install a rooftop solar photovoltaic (PV) system. This price is the cost a household avoids by consuming a kilowatt-hour (kWh) from its rooftop solar system. Consequently, if the levelized cost of a kWh from a solar PV system is less than this retail price, the household saves money by installing a rooftop solar system.[1]

Historically, the retail price of electricity was set by state regulators to approximate the vertically integrated utility's average total cost of providing electricity to its consumers. This average cost is the ratio of the sum of (1) total cost of the transmission and distribution and networks, (2) the total cost of generating and purchasing the electricity sold to final consumers, (3) the total cost of the utility's retailing operations, and (4) the total cost of utility-administered public policy programs designed to achieve social, energy efficiency, or environmental goals, divided by the total amount of energy sold to consumers. In regions of the United States with formal wholesale electricity markets, such as the California Independent System Operator (ISO), the PJM Interconnection, the New England ISO, and the New York ISO, state public utilities commissions (PUCs) continue to set retail electricity prices to recover this average cost.

Average-cost pricing for grid-supplied electricity significantly improves the economic case for a household to adopt rooftop solar, particularly in California. For example, households in the Pacific Gas and Electric (PG&E) service territory currently face an average retail price of 22 cents per kWh for their electricity. Because of increasing block pricing, where the marginal price paid for electricity increases with the customer's monthly consumption, customers can pay up to 40 cents per kWh for their last unit of consumption.

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1 The levelized cost of energy (LCOE) from a generation unit is defined as

$$\text{LCOE} = \frac{\sum_{t=0}^{T}\frac{C_t}{(1+r)^t}}{\sum_{t=1}^{T}\frac{E_t}{(1+r)^t}},$$

where C_t is the net cost of the generation unit in year t=0,1,2,3,…,T, E_t is electricity produced in year t=1,2,…T, r is the discount rate, and T is the number of years the generation unit is in service. If r=0 then the LCOE is simply the average cost of energy over the lifetime of the generation project.

About the Author

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An investment in a rooftop solar system at $3.50 per watt with a 25-year lifetime and assuming a 3 percent discount rate implies a levelized cost of energy of approximately 15 cents per kWh. Substituting 15 cents per kWh energy from a rooftop solar system for 40 cents per kWh electricity from the grid is a fantastic deal for the consumer. Even at the average retail price of 22 cents per kWh, investment in a rooftop solar system makes economic sense for the consumer, without any of the state or federal tax credits or other support mechanisms.

However, this average retail price is also significantly above the annual average marginal cost of supplying the last kWh consumed for any customer in California. According to the California ISO, the annual average hourly price of wholesale electricity as it exits the state's high-voltage transmission network in 2016 was 3.5 cents per kWh.

The major variable costs caused by moving electricity from the high-voltage transmission network to final consumers are the losses that occur between point of injection to the distribution grid and point of withdrawal at the customer's premises. These losses average approximately 5 percent of electricity that is produced each year in the United States. Consequently, the annual average hourly marginal cost of grid-supplied electricity in California during 2016 is very unlikely to be more than 4 cents per kWh.

Inefficient Bypass of Grid-Supplied Electricity

These facts imply that at current average cost-based retail prices, a household would find it privately profitable to install a rooftop solar system, but it would be significantly less expensive on an industry-wide basis for the household to purchase grid-supplied electricity at its hourly marginal cost throughout the year. Under the current retail-pricing paradigm in California, the decision to install a rooftop solar system is something that is privately profitable for the typical household, but it is not the lowest cost source of electricity for that household.

This outcome is the result of average cost pricing of transmission and distribution network services and the costs of utility-administered public policy programs. Virtually all of these costs do not vary with the quantity of electricity delivered to the utility's customers. Because utilities try to recover these largely sunk fixed costs through a per-unit charge, households have a strong incentive to install a rooftop solar system and reduce the total payments they make for the electricity they consume.

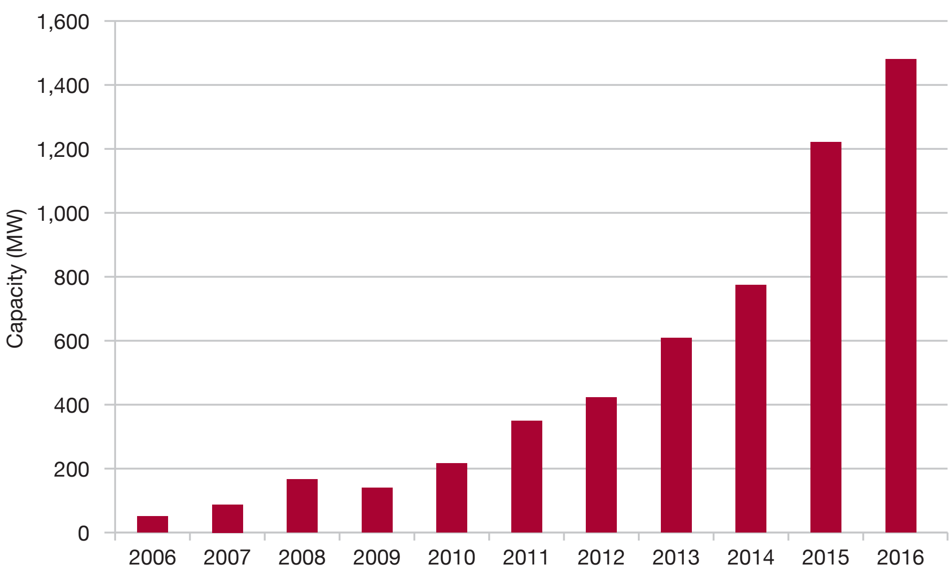
Before the widespread availability of rooftop solar, customers faced with average cost pricing of grid-supplied electricity would simply consume less electricity than they would if the last unit consumed was priced at marginal cost. Customers did not have the option to consume from an alternative source of electricity. The combination average cost-based pricing of grid-supplied electricity and the availability of an alternative source of electricity—a rooftop solar system—creates the economic incentive to adopt rooftop solar.

A Looming Regulatory Crisis

What are the broader implications of average-cost-based pricing of retail electricity? As more distributed solar systems are installed, the quantity of grid-supplied electricity consumed falls. The cents per kWh charge that recovers all of these sunk costs must increase because these costs must be recovered from sales of a smaller quantity of grid-supplied electricity.

According to the California Energy Commission (CEC) there are almost 6,000 MWs of residential and commercial distributed solar systems in the state. The annual additions to self-generation solar PV capacity have substantially increased each year from 2006 to 2016, as shown in Figure 1. This rapid increase in solar capacity implies that the fixed costs of the transmission and distribution networks and utility-administered public programs must be recovered over a smaller amount of grid-supplied electricity, which requires raising average retail prices. But there is no reason to expect that state regulators will continue to raise average retail prices indefinitely to recover these costs, because they are likely to be increasingly borne by less affluent customers.

Figure 1. Annual Additional Installed Self-Generation Capacity



(Source: http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf)

There are a variety of reasons why a regulated utility that invests in the long-lived capital equipment—such as transmission and distribution networks—necessary to provide service to consumers may not recover these sunk costs. Hempling (2015) provides seven examples of a regulated entity that was denied cost recovery, several of which appear applicable to the case of distributed solar investments.[2] All of these reasons follow from the legal mandate that a regulated utility is only allowed the opportunity to recover its costs through prudent operation. Hempling emphasizes that utilities are also not entitled to recover the cost of obsolete capital equipment.

Consequently, one justification for the utility's shareholders bearing the brunt of the revenue shortfalls that result from distributed solar investments is that competition from distributed solar has led to partial obsolescence of the transmission and distribution grid because it is used must less intensively as a result of distributed solar investments. Therefore, the utility's investors now own a less valuable asset and are not entitled to full recovery of these sunk costs.

An argument for full cost recovery is based on the intermittent nature of distributed solar generation. Specifically, the capacity of the existing transmission and distribution grid is necessary to serve both distributed solar and full requirements customers because it is sometimes the case that the distributed solar systems are not producing any electricity, so the annual peak capacity utilization rate of the transmission and distribution grids is the same as it would be in the absence of any distributed solar investments. Only the annual average capacity utilization rate declines because of distributed solar energy production.

However, this argument—that transmission and distribution networks have the same annual peak utilization rates as they did without any distributed solar investments—is increasingly difficult to make as the share of distributed solar capacity increases and the diversity of distributed solar locations increases. Moreover, as more customers install distributed solar systems, the political winds are likely to increasingly blow against full sunk cost recovery. The solar installation trends documented in Figure 1 suggest an increasing urgency for policymakers to address this issue in California.

Another reason to address this issue as soon as possible is based on my own recent research. There is considerable debate over the impact of the rapid growth in distributed solar generation capacity on distribution network costs. Distribution network utilities often argue that network upgrades

2 Hempling, Scott (2015) "From Streetcars to Solar Panels: Stranded Cost Policy in the United States, *Energy Regulation Quarterly,* Volume 3, Issue 3.

are required to accommodate the significant amounts of distributed solar capacity in many parts of their networks. Solar installers argue that distributed solar capacity allows the utility to avoid many investments in network upgrades.

In this research, I study the relationship between quarterly average distribution network prices for the three investor-owned utilities in California—PG&E, Southern California Edison, and San Diego Gas and Electric—and the total amount of solar PV capacity installed in each utility service territory at the start of that quarter. I find empirical evidence in favor of the hypothesis that distribution network charges have increased more than can be explained by the mechanical impact of less total withdrawals of grid-supplied electricity.[3]

Specifically, even after controlling for a slowdown in the growth of withdrawals of grid-supplied electricity in each utility's service territory, higher levels of cumulative solar installs are associated with higher distribution charges for residential customers in that utility's service territory. I find that the approximate doubling of the average residential distribution charge for each investor-owned utility between 2003 and 2016 can be almost entirely explained by increases in the fixed cost of the distribution network, presumably due to investments to accommodate more distributed generation capacity. I also find evidence that these distribution charges increased more in utility service territories with more geographic concentration in the installed capacity of the distributed solar PV systems.

These empirical results imply that the distribution utilities are currently in the uncomfortable position of making sunk investments in their networks to accommodate distributed solar PV systems that may eventually be rendered obsolete by future investments by customers in distributed solar systems and batteries and other load-shifting technologies.

Toward More Efficient Retail Pricing

So what can be done to address this looming regulatory crisis in sunk cost recovery? The first step is for the California Public Utilities Commission (CPUC) to implement a retail pricing mechanism that reflects the reality that grid-supplied electricity now faces competition from distributed solar PV systems. Retail prices must be set so that the private cost versus benefit calculation for a household investing in distributed solar PV capacity is consistent with the societal cost versus benefit calculation for this investment. This is accomplished through marginal cost pricing of grid-supplied electricity to retail customers.

Each hour of the day, the retail price faced by a household should be equal to the hourly marginal cost of supplying an additional kWh of grid-supplied electricity to that customer. This marginal cost is equal to the hourly wholesale price plus the marginal losses associated with delivering that kWh to the customer through the transmission network and distribution network.

Returning to our earlier example, if the customer pays the delivered marginal cost of electricity each hour of the year, the customer will invest in distributed solar only if the annual average marginal cost of grid-supplied electricity is greater than the levelized cost of a distributed solar installation. This decision rule is consistent with minimizing the societal costs associated with supplying that customer with electricity on an annual basis.

This approach to retail pricing also ensures that a household's choice between grid-scale solar and rooftop solar will minimize the system-wide costs of meeting aggregate demand for electricity in the utility's service territory. Consider the case of customers that can purchase utility-scale solar energy or install distributed solar capacity on their premises. If the difference between the levelized cost of energy from the rooftop solar system versus a

3 Wolak, Frank A. (2017) "The Economic Impact of Inefficient Distribution Network Pricing: Evidence from California and a Framework for a Proposed Solution," available at http://www.stanford.edu/~wolak.

utility-scale solar system is larger than the annual average of the hourly marginal costs of delivering a kWh of energy to the household from the utility-scale system, then the utility-scale system is the preferred source of solar energy. Delivering utility-scale solar energy to the customer would require paying the hourly marginal cost of moving the energy from the point of injection of the energy into the transmission network to the point of withdrawal on the customer's premises and this cost is avoided by the customer installing a distributed solar system on his premises. Consequently, marginal pricing of the transmission and distribution networks would also align public and private incentives for utility-scale versus distributed solar PV investments.

The only significant conceptual challenge with marginal cost pricing of the transmission and distribution networks is that this may not result in sufficient revenues to recover the sunk costs of these networks. The most straightforward way to recover this additional cost is through a customer-specific monthly fixed charge. I have developed a framework for determining how this monthly fixed charge would vary across customers according to their willingness to pay.[4]

The basic insight from this analysis is that the annual total of these monthly fixed charges for each customer should not be so high to cause any customer to opt out of access to grid-supplied electricity. At the other extreme, the annual total of all monthly fixed charges across customers should be sufficient to recover the utility's remaining costs, net of the revenues received from marginal cost pricing of grid-supplied electricity.

This approach to retail pricing implies a transition to a monthly cable bill approach to pricing access to the transmission and distribution network. Analogous to how cable customers pay a monthly fixed charge to watch as much programming as they like on any of the channels they subscribe to each month, the distribution utility's customers will pay a monthly fixed charge that allows them to consume as much grid-supplied electricity as they would like at the hourly marginal cost of providing this electricity.

My analysis implies that customers pay different monthly fixed charges based on their annual willingness to have access to grid-supplied electricity. Customers with higher average and more variable hourly demands that face more variable hourly marginal costs of retail electricity that are more highly correlated with their hourly demands should face higher monthly fixed charges because of their greater willingness to pay for grid-supplied electricity.

It is important to emphasize that a default hourly retail price of energy equal to the hourly marginal cost of providing the household with electricity does not mean that the households cannot purchase a hedge against this hourly price risk. Similar to how households insure against monthly bill risk for their cell phones by advance purchases of monthly minutes at a fixed price, customers can make advance purchases of a monthly load shape for grid supplied electricity at a fixed price and only be exposed to the hourly price for deviations from this load shape.[5]

Demand Charges— What Not To Do

A popular proposal among utilities for dealing with this sunk cost recovery problem is to impose demand charges. These require the customer to pay a dollar per kW charge based on her peak demand within a given time period, typically the monthly billing cycle. The utility would measure the customer's consumption during all hours or smaller time intervals within the month and charge per kW for the highest recorded value of the

4 Wolak, Frank A. (2017) "The Economic Impact of Inefficient Distribution Network Pricing: Evidence from California and a Framework for a Proposed Solution," available at http://www.stanford.edu/~wolak.

5 For a detailed discussion of this proposal see Section 4.3 of Wolak, Frank A. (2013) "Economic and Political Constraints on the Demand-Side of Electricity Restructuring Process," *Review of Economics and Institutions,* Vol. 4, No. 1. Article 1.

instantaneous demand for grid-supplied electricity during that time period.

Unless the customer's consumption of grid-supplied electricity is highly correlated with the peak demand on the distribution system, a demand charge does little to reduce the system peak demand or reduce the amount of future transmission and distribution network investments. Because every customer has a monthly peak demand, demand charges can be a very effective way to raise revenues, but it makes very little economic sense to assess a demand charge on a customer whose monthly peak demand occurs, for example, at 2 a.m. on a weekend.

Assessing a demand charge on a customer's consumption during the monthly peak for system demand or total demand within that customer's distribution network does provide an incentive to reduce demand during the highest demand period of the month and thereby reduce the need to upgrade the distribution network. However, this approach still requires an administrative process to set the value of the demand charge, whereas setting the retail price equal to the hourly marginal cost of delivering energy to that customer does not. This approach to a demand charge fails to recognize that there are many other reasons that the transmission or distribution network operator would want a customer's demand to be reduced. For instance, a transmission or generation unit outage during low system demand conditions could create a supply shortfall in a local area, which means that customers in that area reducing their demand would benefit grid reliability. Hourly marginal cost pricing would send the economically efficient price signal to those customers to reduce their demand, whereas a system-peak demand charge would not.

Conclusion

The transition from an electricity supply industry with dispatchable utility-scale generation units delivering grid-supplied electricity to consumers to an industry where consumers have the option to install distributed solar generation has created the opportunity for customers with the ability to install a distributed solar system to reduce the amount they pay for the sunk costs of the transmission and distribution networks and utility-administered public policy programs.

This paradigm shift in the electricity supply industry requires a change in how these costs are recovered from retail electricity prices. Marginal cost pricing of grid-supplied electricity with recovery of the remaining sunk costs through monthly fixed charges will align private and societal incentives for investments in distributed solar capacity. It will also lead consumers to make the choice between utility-scale solar and distributed solar investments that minimizes the system-wide cost of meeting any renewable energy mandate.

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