Future of Retail Rate Design

Edited by Eric Ackerman & Paul De Martini

Introduction

Rates need to change. Customer adoption of distributed energy resources and the changing use of the distribution system mean that existing retail rates and service tariffs are creating an unsustainable path forward for both electricity customers and industry. A growing number of customers are increasingly exercising their options to manage electricity bills through energy efficiency, demand management and onsite generation. The result is that annual load growth is expected to less than 1% through 2035.[1] Distributed energy resources (DER)[2] allow customers to become more self-sufficient, but no less dependent on electric distribution infrastructure for delivery of excess and supplemental energy to and from markets, basic frequency and voltage stability and fundamental reliability.[3] As Philip May, CEO of Entergy Louisiana proposed, "The challenge is find an equitable way to integrate distributed generation (DG) into the grid. It should be equitable to all. It should be equitable to the DG customers it should be equitable to the non DG customers. It also needs to be equitable to the Utilities."

New uses of the grid, especially the need to manage intermittent resources, requires investment in advanced technologies at the same time as aging distribution components are being replaced. Investor-owned electric utilities are investing about $21 billion a year for these purposes. A key issue is that current retail rate designs allow DG customers to avoid their fair share of fixed network costs, effectively shifting these costs to non-DG customers through higher rates. This is not sustainable, given the potential for widespread DER adoption.[4] The challenge was highlighted by MIT in their "Future of the Electric Grid"[5] study:

> "*The U.S. electric power industry must invest significant amounts of capital over the coming decades to replace aging assets and expand the network to meet incremental load growth. That investment easily could double if utilities deploy new transmission and distribution technologies to improve system operation; enhance service quality; and accommodate new types of generation, load, and demand response. To deliver on these promises in the most efficient and cost-effective manner, the regulatory systems and policies that oversee the U.S. grid also must be modernized.*"

This paper is part four of the Future of Distribution series and highlights key issues raised by grid modernization and the development of DER at scale. The challenge is to develop new rate policies that allow us to integrate DER into the electric system while ensuring reliability, safety and fairness to all customers. The discussion draws on comments elicited during an EEI webinar, *Utility Rate Design for Sustainable Distribution*, November 27, 2012. Included in this webinar were Mike Campbell, Program

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[1] Energy Information Agency, Annual Energy Outlook 2012

[2] Distributed energy resources include all forms of distributed generation, energy storage, responsive demand and electric vehicles.

[3] According to micro-grid developers, Pareto Energy and Horizon Energy most customer micro-grid developments fulfill no more than 85% of energy needs. These micro-grid and net zero energy installations are based on annual averages and consume energy from the grid during periods of the day when not producing electricity sufficient to meet consumption. Also, in current practice neither is able to maintain frequency and power quality independent of the electric grid for sustained periods.

[4] P. De Martini, editor, Customer-Grid Evolution, EEI, 2013

[5] MIT Energy Initiative, The Future of the Electric Grid", MIT, 2011

Manager, Electric Pricing and Customer Programs, California Public Utilities Commission Division of Ratepayer Advocates; Robert Curry, former Commissioner, New York Public Service Commission; Phillip May, VP, Regulatory Services, Entergy Services, Inc.; David Owens, Executive Vice President, EEI; and Professor Richard Schmalensee, Howard W. Johnson Professor of Economics and Management Emeritus at the Massachusetts Institute of Technology and the Director of the MIT Center for Energy and Environmental Policy Research in the Sloan School of Management.

First Principle: Fairness

The goal of regulation is to ensure that rates are "just and reasonable." Rates must be fair (just), and must promote economic efficiency. To ensure fairness, regulation traditionally has observed the principle of cost causation: the customer who causes a cost to be incurred (e.g., the cost of transmission and distribution facilities needed to interconnect and serve the customer) should pay those costs, not other customers. To promote efficiency, regulation favors rates that convey "proper price signals;" that is, prices which accurately reflect the costs incurred to serve customers. Rate designs which recover both fixed and variable costs through kWh charges fail to meet this test too. As Professor Schmalensee points out, recovering both fixed and variable costs through kWh rates is "not efficient and its fairness is not obvious."

A key issue today is that a kilowatt-hour consumption rate is not a good measure of the long run of cost causation related to distribution systems and operational fixed costs. This is compounded by onsite generation, such as rooftop solar, where excess energy is sent back into the grid and supplemental energy is delivered. Excess energy results from residential solar photovoltaic system output that is typically non-coincident with the home load profile. Plus, the average size of newer residential solar PV systems is now 7kW, and expected to reach 10kW by 2020, exceeding the 4kW peak demand of the average home - producing excess energy back into the grid for most daylight hours during the year. Today, this bi-directional use of the grid is netted out, with the result that DG customers' use of the distribution system is under-reported and related costs reallocated to other customers. As a first principle, retail rates should be equitable to all customers using the grid as well as utilities.

> "State regulators and those who supervise government-owned and cooperative utilities should recover fixed network costs primarily through customer charges that may differ among customers but should not vary with kilowatt-hour consumption"
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> MIT Future of Grid

Contributing to the unfairness of current rates and the need for reform is the recognition that residential and commercial customers are increasingly differentiated. Traditional rates were designed decades ago based on very homogeneous classes of customers. However, those customers with DER are no longer part of the homogeneous class that was the basis for the rate design. For example, residential net metering customers are often on the same rate class as other residential customers even though their load profile and usage patterns are dramatically different. Residential customers who do not have distributed resources may fit within the parameters of the original rate design, which may still be reasonable. But it may not be reasonable to include DER customers in the same class with non-DER customers. The same can be true for commercial customers. It may be appropriate to have a completely separate rate class for DER customers.

Retail rate policy and redesigns should consider evolving customer classes, cost-shifting among customers, and reasonable cost allocation based on cost-causation. These polices need to be fair to customers with distributed resources, those customers without, and the industry alike. As Mike Campbell observed, “the big [DER] incentive goes to the highest consuming customer and there isn’t much incentive for the lower usage customers.” A suggested policy guide is that customers without DER and utilities should not be responsible for any costs caused by customers with distributed energy resources. That responsibility for should be borne by the DER customers themselves. This is not simple in practice, particularly given the various parties’ interests.

Distributed Resources at Scale

Distributed resources are recognized as having benefits for customers and the power system. However, the integration of these resources at scale poses regulatory and rate issues related to specific benefit valuation, integration and operational cost allocation and recovery and alignment of incentives. These issues are no longer isolated to a few states – “this is not simply a California issue”, shared Philip May.

<u>Benefits of DER</u>

Distributed energy resources including all forms of distributed generation, energy storage, responsive demand and electric vehicles offer significant potential benefits in terms of reduced emissions and increased efficiency. Southern California Edison identified 22 different services and values across the electricity value chain in the chart below that may be applicable to DER. (Figure 1) In many cases DER values are location- specific, not unlike resources connected to the bulk power system. This means that some values may be positive or negative depending on grid conditions as described below. A key challenge is that we do not yet have industry standard engineering-economic models that can quantify potential benefits of DER, taking into account the dynamic nature of intermittent solar PV and small wind resources on distribution systems.

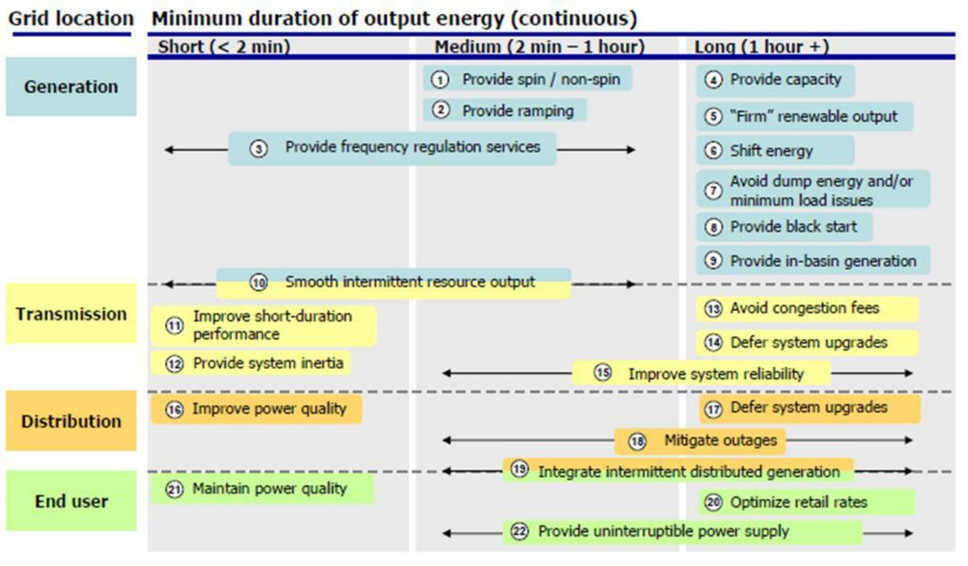

Figure 1 SCE Potential Value from DER

Fixed Infrastructure & Operational Costs

The current distribution system is usually able to handle a small amount of distributed energy resources without causing safety or reliability problems. As DER market penetration increases, however, the problems created by two-way flow of power on distribution systems are increasing. Utilities are incurring additional costs to accommodate these new power sources so they can continue to operate the system without overloading circuits or jeopardizing the safety of utility workers and the public. There are generally three types of integration costs that are becoming more visible over time, as follows:

- **Local distribution infrastructure costs** related to incremental investments to enable individual DG installations that cannot be currently accommodated or as DER begins to have a significant presence on individual distribution lines or circuits. These costs are generally covered in existing utility interconnection planning processes and line extension and service tariffs.
- **Operating costs** to accommodate variable resources like wind and solar photovoltaic generation require system support capabilities such as operating reserves, regulation and "load following" (control of power output in relation to demand) to maintain grid reliability. These costs will be relevant to the integration of large amounts of intermittent distributed generation.
- **System-wide grid modernization costs** when the total installations or megawatts exceeds what the utility previously planned to accommodate, there will be additional system investments beyond those needed for individual lines or circuits. System incremental upgrade costs include those associated with enhancements to protection and control systems and system-wide installation of power electronics devices. Incremental O&M expense related to these upgrades

also is incurred. The additional system infrastructure costs in the U.S. may total as much as $100 billion through 2030.[6]

"*Electricity pricing also needs to be changed to deal with the growth of distributed generation and efficiency initiatives. Utilities currently recover the largely fixed costs of transmission and distribution networks through volumetric charges per kilowatt hour of use, a practice that distorts the relative prices of central station generation and distributed generation. Under this regime, a customer who generates electricity on-site rather than purchasing it from the local distribution utility saves both the energy charge and the distribution charge for that electricity, but the utility saves only the corresponding generation cost because the cost of distribution is almost entirely unchanged. (Indeed, if a high concentration of distributed generation required modification of the distribution system, that fixed cost may be increased.) This outcome is the same regardless of the energy source—clean solar or dirty diesel—used by the distributed generator. The remedy is straightforward, at least in principle: recover fixed network costs mainly through non-volumetric charges."* MIT Future of the Electric Grid

Net Energy Metering

Net energy metering (NEM) refers to a state-level policy that encourages distributed generation (DG) by paying DG customers for the power they generate. Self-generating customers typically are credited at the utility's full retail rate for the power they produce, including kWh they consume, and kWh they export to the grid. In addition, power that DG customers produce in excess of what they need during a billing cycle results in credits at the full retail rate that can be applied against the customer's bill during later billing cycles, when it is not producing enough power to meet its own needs. Some states provide for additional credits, such as for excess energy at the end of a 12-month period. Net metering allows self-generating customers to avoid paying their full share of utility distribution service. Also important, NEM does not allow for recovery of backup service costs when the distributed generator is not working.

Net metering began in the early 1980s to encourage development of DG by providing a subsidy. At that time, distributed generation was new and unproven in the marketplace. Today, forty-three states and the District of Columbia have net metering programs and nearly 90,000 MWs of customer generation is installed. These incentive rates are in addition to federal and state tax subsidies. Net metering participation consists mostly of residential and small business customers. Some states allow other types of customers to participate such as large industrial companies and schools.

Net metering creates several problems now that DG is reaching significant scale. Not all customers have a self-generation option. For example, customers must have a viable location for solar PV or small wind and the financial means to afford the installation or lease. Also, customers that use the most energy have the most value to gain from self-generating. This means a large majority of customers may not benefit as today about 57% of US households[7] own their home and only a subset of those will qualify. This is referred to as the "green energy divide." This poses two fundamental issues. Most problematic is

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[6] De Martini, P., Future of Distribution, Edison Electric Institute, July 2012

[7] US Census Bureau, 4th Quarter 2012 Homeownership Statistics, January 2013

that a sizable minority of customers will be shifting significant costs to the majority of customers that cannot adopt distributed generation. This, in turn, may cause rates to rise and improve the cost effectiveness of DG which causes more to adopt and absent rate reform, could lead to unsustainable economic conditions.

Net metering also doesn't involve the value of the generation on the system. Two neighbors evaluating the same rooftop solar system could be seeing different values from the net metering incentive based on their energy consumption. The value of generation and other forms of DER on the grid has locational value – either positive or negative – but also is not addressed. As described above there are benefits and costs associated with integrating DER into the power system but the associated values have not yet been fully identified and characterized. The issue relates to the dynamic nature of intermittent resources and lack of sufficient modeling tools to assess the impacts at distribution. Locational based pricing on distribution has practical limits in that businesses and consumers cannot easily move to seek better retail rates – but the locational value of the generation should be considered.

Net metering, unfortunately, also causes misalignment of incentives between customers and utilities. Those customers that add distributed generation save the entire applicable rate - both their contribution to fixed and variable costs. The utility only saves the variable generation cost, creating an incentive to resist distributed generation. This problem was highlighted in the recent Hoover Institution report[8]:

"Absent reform, this rate design means that rising IOU costs in the residential sector are set to fall on a narrow base of customers whose incomes and consumption exceed rate protection but who do not install rooftop PV panels. In fact, though current policies are encouraging rapid PV deployment in the short term, the rate imbalances being created could actually limit the broader, market-driven scale up of these key technologies by aligning utility and consumer interests against them."

The remedy often discussed is decoupling, which allows the otherwise shortfall in revenue to be collected through nearly automatic reallocation to other customers through higher rates. Prof. Schmalensee described decoupling as "instutionalizing cost shifting." This is an issue, but potentially worse is the effect rising rates has on adoption. In the short-term when adoption is low the effect on rates is negligible. But, as the adoption percentage reach double digits the self-reinforcing feedback of higher rates (and lower solar PV costs) creates greater incentive for adoption. The results may be dramatic as highlighted by research at Caltech.[9]

To address these issues, tariffs for distributed generation in concept could include three parts:

- Market and local operational based price for excess energy and grid services (variable charge)
- Utility portfolio price for energy consumed (variable charge)

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[8] J. Carl, D. Grueneich, et al, Renewable and Distributed Power in California, Simplifying the Regulatory Maze, Stanford University, November 2012

[9] D. Cai, S. Adlakha, et al, Impact of Residential PV Adoption on Retail Electricity Rates, Caltech, 2012

- Network access charge for bi-directional grid use (fixed charge)

Cautionary Examples

The implications of failing to update retail rates are significant as illustrated by the Spanish power industry and US telecom industry. If this seems implausible, consider the current situation in Spain where government renewable energy policies and an unwillingness to allow retail rates to rise led to a $33 billion revenue gap for utilities between cost of power and customer revenues – an amount nearly equal to total annual utility revenues. The recently announced remedy is elimination of renewable subsidies and a 7% tax on all forms of bulk generation – no increases in regulated customer rates.

Commissioner Curry shared that, "20 years ago the largest operator then of universal wireline business came to state regulators with a proposition that the revenues from its new wireless business should be kept separate and apart from those of the copper wire system. Regulators agreed and so became the death spiral of the wireline business. Although technological change demanded a new business model [for the wireline business] none was developed." The telecommunications industry continues to struggle with cost recovery and pricing, not only with its declining basic wireline service, but also with broadband and wireless services from massive video streaming via "free" business models like YouTube. The failure to adapt to new disruptive technology is reflected in Figure 2, which charts communication revenues between 1980 and 2008. Notice that after passage of the Telecom Act in 1996, revenues from wireline service declined steadily, while revenues from mobile communications, internet data and video services, and ecommerce all grew vigorously. The electric industry is facing analogous issues in several regions today and to Mr. Curry's point there are lessons to be learned.

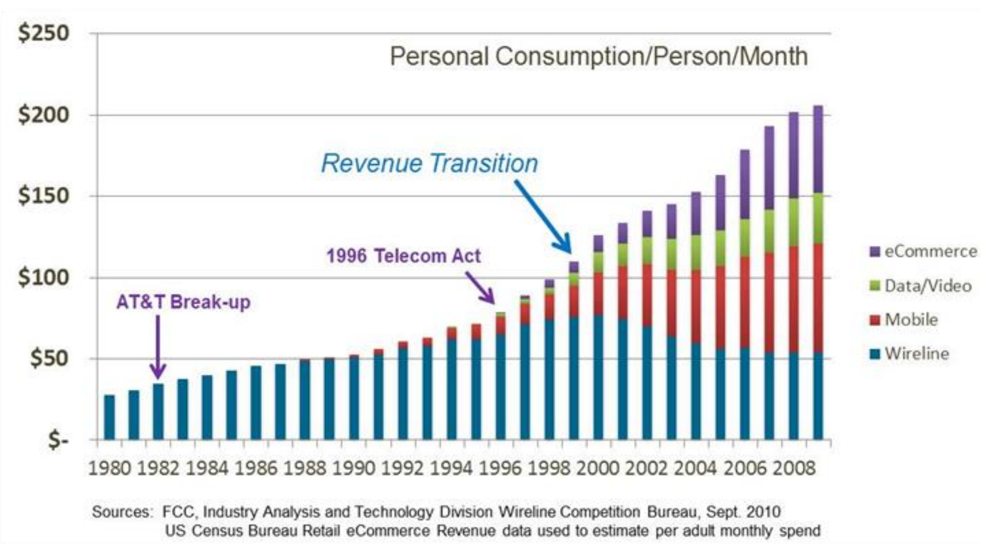

Figure 2 Telecom/Internet Personal Spending

Conclusion

There is an urgent need to update retail rates. We need rate policies which allow us to integrate DER into the electric system while ensuring reliability, safety, and fairness for all customers. This requires a holistic perspective on electricity markets and how they are evolving under the influence of new technologies. Shifting costs from those continuing to use the grid to those that are not able to participate in onsite generation is unacceptable. Neither are declines in utility credit worthiness and financial health.

Utility investment in replacing aging infrastructure and modernization is needed given the importance of electricity as an essential aspect of modern life and the prime mover of the modern economy. However, in order to make these significant investments utilities need access to capital on reasonable terms. This requires financial strength based in large part on reasonable cost recovery. Philip May described the situation, "The last time this industry had that level of spending 97% of our companies were at least A rated. Today, 80% of our companies are triple B or lower." Utilities will continue to improve operations with a focus on reducing costs. But, as an industry we need to consider different ways to recover the costs of maintaining safety and reliable electric service.

Steady, thoughtful, sustainable public policies are needed as technologies and customer options evolve. The following conclusions provide a starting point for collaborative discussions:

1. Retail rate policies need to be updated as technologies and markets evolve.
2. The key to sustainable policies is ensuring reliability, customer equity, and safety.
3. Customer equity requires that fixed costs be recovered through fixed charges.
4. Customer equity also requires that net energy metering policies credit DER customers for energy-only, reflect the locational value of excess generation produced, and take account of the services which DER customers receive from and may provide to the grid.
5. Better alignment of customers, utilities, DER developers and others' incentives is also needed for sustainable growth and transformation of the electric industry

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