

# Rate Design for a Distributed Grid

Recommendations for Electric Rate Design in the Era of Distributed Generation



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# 1. Executive Summary

In response to the growing popularity of rooftop solar and other distributed energy resources (DERs),<sup>1</sup> some electric utilities have recently begun seeking ratemaking changes that would discourage customers from generating their own power and otherwise buying less electricity from their utility. These changes – which include higher fixed charges and reduced compensation for exported energy – are justified by a purported concern about costs being shifted among customers of the same rate class.

The utilities' ratemaking ideas are often expressed by the Edison Electric Institute (EEI), most recently in a rate design "Primer" sent to the National Association of Regulatory Utility Commissions (NARUC).<sup>2</sup> In that document, EEI makes three fundamentally incorrect assumptions about rate design: (1) that a very large proportion of a utility's costs should be considered "fixed" costs; (2) that distributed generation and conservation do not substantially reduce those "fixed" costs or provide other benefits beyond avoiding the short-run energy cost; and (3) that rates based on volumetric energy usage and net metering invariably cause costs to be shifted from low-usage customers and those who self-generate to high-usage ones.

This paper responds to EEI first by examining the allegation that rooftop solar shifts costs onto other utility customers. We point out that the assumption of a cross-subsidy rests largely on the premise that self-generation provides no benefit to the utility and its ratepayers other than reducing the short-run cost to buy or generate power. To the contrary, we show that rooftop solar provides a wide range of benefits, including avoided generation, transmission and distribution capacity, lower wholesale market prices, reduced volatility, and avoided pollution.

In fact, when the full range of avoided costs and other benefits is considered in a complete cost-benefit analysis, solar net energy metering (NEM) – which provides retail credit for solar energy exported to the grid – has been shown to convey net benefits to non-participating ratepayers. A recent meta-analysis of net metering cost-benefit studies by the Brookings Institution concluded that "net metering is more often than not a net benefit to the grid and all ratepayers."

Next, we offer some rate design principles aimed at achieving broad ratepayer and societal benefits. Good rate design empowers customers to control their energy costs through conservation and adoption of emerging technologies while sending price signals that efficiently allocate capital investment, which can lower costs for all ratepayers. Rates should not be designed simply to protect utilities from competition, and customers are entitled to universal service, usage-based pricing, and fair compensation for energy exports.

Finally, we offer a series of reforms that could better integrate DERs into the electric grid and maximize their value to ratepayers. In particular, DERs should be included in long-term resource

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<sup>1</sup> "Distributed Energy Resources" include rooftop solar, energy efficiency, demand response, smart inverters, battery storage, controllable electric loads and other energy resources located behind the customer meter.

<sup>2</sup> "Primer on Rate Design for Residential Distributed Generation," Edison Electric Institute, February 14, 2016. <http://www.puc.state.pa.us/pcdocs/1423623.pdf>

planning so that utilities are not building new infrastructure, such as power plants and transmission lines that could be replaced by DERs at lower cost. In tandem with incorporating DERs into utility planning, regulators should consider changes to the utility business model – including revenue decoupling and new ratemaking mechanisms – that would mitigate the utility’s financial incentive to choose rate-based capital expenses over customer-owned resources as a means to satisfy infrastructure needs.

We conclude this paper by offering the following recommendations:

- **Study the impact** of distributed resources by conducting a rigorous analysis of the costs and benefits
- **Design electricity rates that empower customers** to control energy costs and adopt new technologies that provide system benefits
- **Implement technology standards** to gradually increase the functionality and benefits of distributed resources
- **Incorporate distributed resources into utility planning** in order to defer or replace traditional infrastructure
- **Update utility business models** so that utilities have greater financial incentive to rely upon customer-sited distributed resources to meet infrastructure needs
- **Implement rate changes gradually** and incrementally, with grandfathering for customers who made long-term capital investments on the basis of previously existing rates

## 2. Behind the Premise of Cost-Shifting

### 2.1. EEI Largely Ignores the Avoided Costs Resulting from DER Deployment

EEI's arguments about rate design rest on the false premise that solar NEM customers "shift costs" onto non-NEM customers because NEM causes the utility to lose revenue in excess of the cost savings resulting from rooftop solar. This construct overlooks the numerous ways in which solar and other distributed resources make the electric system less expensive in the long run.

For example, while EEI asserts that as much as 70% of a utility's costs should be considered "fixed,"<sup>3</sup> utilities often define "fixed costs" very loosely, including shareholder return, income taxes, labor, transmission and distribution costs, and sometimes even some generation-related costs.<sup>4</sup> Viewed over the proper timespan, many of these infrastructure costs should be considered variable costs – and indeed are among the kinds of costs that investment in DERs can avoid.

Thus, EEI mistakenly assumes that reducing energy consumption through conservation or self-generation saves utilities only the short-run wholesale "energy" portion of their costs, and not the capacity or fixed infrastructure costs. Such a viewpoint presents an incomplete picture by focusing solely on short-run avoided energy cost and ignoring long-run avoided costs.

Contrary to the opinions presented in the EEI memo, in the long run, DERs can avoid a wide range of fixed infrastructure costs, including generation capacity, distribution capacity and transmission capacity while improving power quality and reliability. Although utilities have a financial interest in having regulators believe that these infrastructure costs are "fixed" – since their profits are tied to those investments – there is no doubt that many infrastructure costs are indeed avoidable over the long term through distributed solar and other DER investments.

First, by reducing peak demand, rooftop solar and other DERs reduce expensive energy and capacity needs. While it is possible to reach a point where additional solar no longer affects peak demand – if that demand shifts to post-solar hours – the experience in Hawaii at least through 2014 was that solar and efficiency reduced peak demands, as shown in Figure 1.<sup>5</sup>

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<sup>3</sup> See EEI Primer on Rate Design, <http://www.puc.state.pa.us/pcdocs/1423623.pdf>

<sup>4</sup> See Lazar et al, Smart Rate Design for a Smart Future, <http://www.raonline.org/document/download/id/7680>.

<sup>5</sup> Hawaiian Electric Power Supply Improvement Plan, 2014.

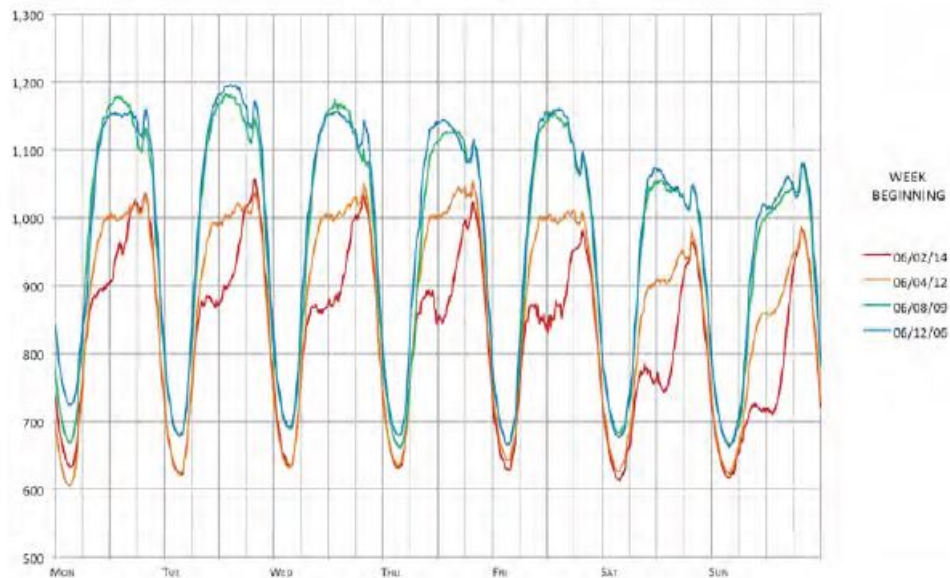


Figure 1: Oahu System Load Profiles, 2006 - 2014

In addition, distributed resources like rooftop solar reduce the need for transmission capacity – in spite of arguments made by utilities to the contrary. For instance, in its most recent transmission plan at the California Independent System Operator (CAISO), Pacific Gas and Electric Company (PG&E) recently cancelled nearly \$200 million of planned transmission investments due to lower-than-expected load growth resulting from rooftop solar and energy efficiency.<sup>6</sup> Despite crediting rooftop solar with avoiding the need to make these major transmission investments in statements to CAISO, PG&E claimed that rooftop solar has zero potential to avoid transmission costs in separate filings related to net metering at the California Public Utilities Commission (CPUC).<sup>7</sup>

Beyond reducing peak demand and avoiding costly transmission investments, rooftop solar and other DERs provide direct financial benefits to utility ratepayers in other ways that are not captured by the EEI framework. For example, because it has zero operating cost, rooftop solar reduces the clearing prices in wholesale energy and capacity markets. In fact, the eastern regional transmission organizations (RTOs) now account for the presence of distributed solar in calculating the RTOs’ forward capacity needs, reducing capacity procurement costs. A recent analysis by ICF International found that rooftop solar will save customers in the three eastern RTOs \$2 billion in capacity costs in 2019.<sup>8</sup>

Furthermore, solar and other DERs provide savings by reducing the cost of hedging volatile fossil fuel prices. As Edison International Chairman Theodore Craver Jr. put it during a recent Edison earnings call: “[S]ince renewables have no fuel cost, customer rates are increasingly less exposed to future natural gas price spikes. All of this helps to keep our rate increases modest and electricity affordable...”<sup>9</sup>

<sup>6</sup> “Cal-ISO Board Approves Annual Transmission Plan.” California Energy Markets, April 1, 2016.

<sup>7</sup> PG&E, “Comments on Party Proposals and Staff Papers” filed in R. 14-07-002, Sept. 1, 2015

<sup>8</sup> <http://www.seia.org/blog/dothemath-how-rooftop-solar-will-save-us-billions>.

<sup>9</sup> “Edison Earning Drop, but Utility Has Rosy Outlook.” California Energy Markets, May 13, 2016.

Thus, to claim a “cost-shift” by comparing the retail value of NEM credits with the wholesale energy rate, as EEI attempts to do, is to oversimplify the accounting of costs and benefits in a way that is self-serving to the utilities’ interests. When the full suite of avoided costs of distributed solar are properly accounted for, rooftop solar often provides a net benefit to non-participating ratepayers, even under full retail NEM.

## **2.2. Studies show that benefits of rooftop solar exceed costs to ratepayers**

When determining the effect of a policy on ratepayers, it is important to consider all of the costs and all of the benefits of that policy over a sufficiently long time horizon. For decades, regulators have promoted conservation programs that might increase costs for non-participating ratepayers in the short run but reduce total system costs in the long-run. Such policies have generally been considered to benefit ratepayers as a whole, in large part due to these system-wide cost reduction benefits and the elimination of rate-increasing capital additions to serve load growth.<sup>10</sup>

Thus, in order to determine whether net metered rooftop solar imposes net costs or benefits to non-participating ratepayers, it is necessary to conduct a comprehensive study of costs and benefits, including effects that may be hard to quantify, such as those concerning wholesale market prices and volatility. Such studies have been conducted by the federal and state governments, non-profit organizations and private firms across a number of different states over the past several years.

These studies, which are collected on the SEIA website,<sup>11</sup> show that in most cases, the benefits of rooftop solar exceed the costs to non-participating ratepayers. In a recent meta-analysis conducted in 2015, Environment America found that eight analyses out of 11 concluded that the value of solar energy was worth more than the average residential retail electricity rate in the area at the time the analysis was conducted. The three analyses that found different results were all commissioned by utilities.

Furthermore, a recent report by the non-partisan Brookings Institution analyzing all of the major cost-effectiveness studies to date found that net metering provides a net benefit to ratepayers. The paper finds that: “In short, while the conclusions vary, a significant body of cost-benefit research conducted by PUCs, consultants, and research organizations provides substantial evidence that net metering is more often than not a net benefit to the grid and all ratepayers.”<sup>12</sup>

For this reason, it is important for policymakers to look beyond the simplistic framework presented by EEI that compares the wholesale energy price to the retail electric rate. A full accounting of the costs and benefits of net metering across all customer classes should be undertaken for any particular state or region before a determination is made that changes are warranted to rectify unfair cost-shifting between customers within a class of ratepayers.

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<sup>10</sup> Ari Peskoe, “Unjust, Unreasonable and Unduly Discriminatory: Electric Utility Rates and the Campaign against Rooftop Solar.” February 1, 2016. The Texas Journal of Oil, Gas and Energy Law, 2016, Forthcoming.

<sup>11</sup> <http://www.seia.org/policy/distributed-solar/solar-cost-benefit-studies>

<sup>12</sup> The Brookings Institute: “Rooftop solar: Net metering is a net benefit,” by Mark Muro and Devanshree Saha. May 23, 2016. <http://www.brookings.edu/research/papers/2016/05/23-rooftop-solar-net-metering-muro-saha>

## 2.3. Concern for cross-subsidies as red herring to stifle customer choice

In a recent paper entitled, “Unjust, Unreasonable and Unduly Discriminatory – Electric Utility Rates and the Campaign Against Rooftop Solar,” Ari Peskoe of the Harvard Environmental policy initiative examines the utilities’ arguments for rate changes in response to rooftop solar. In the paper, Peskoe observes that “[Investor owned utilities] have launched a nationwide campaign against cross subsidies, in the name of consumer protection,” claiming that “failure to adopt their rate design proposals would allow subsidies between customers” and proposing rate structures that would “substantially reduce customers’ incentives to generate their own electricity or buy less from the IOU.”<sup>13</sup>

As Peskoe points out, however, a number of studies have found that “net metering’s effect on rates is minimal or that decentralized PV adds sufficient value to the system to justify a compensation mechanism that does not focus exclusively on utility costs.” Peskoe concludes that intra-class cross subsidies are an intentional distraction and that undue discrimination against competition should be the focus. “Several state courts have held that PUCs should align rate design with utility costs, but rate design need not be limited to matching rates with costs,” says Peskoe. Furthermore, the paper states “the ultimate purpose of regulation is to protect consumers, not the IOU.”

Indeed, the regulated utility has enjoyed a century of relative freedom from competition to serve small-use residential and commercial customers. Monopoly regulation was created in the 19<sup>th</sup> century to protect railroad customers from discriminatory pricing,<sup>14</sup> and the regulatory framework has historically served to protect customers from monopoly abuse. Regulation should enforce pricing discipline on distribution monopolies, not stifle customers’ desire to invest in innovative technologies that will both lower their bills and lower system costs, while contributing to the creation of a modern, clean, and reliable grid. In weighing potential rate changes, regulators should consider the potential benefits competitive energy providers could bring to the sector through competition and innovation, and should be mindful of the customers’ desire to choose technologies that allow them to manage energy costs.

## 3. Rate Design Should Empower Customers

By pointing to a supposed mismatch between the fixed component of utility costs and rates, EEI in its rate design Primer implies that “cost-shifting” could or should be addressed by increasing the fixed component of rates. This view is contradicted, however, by EEI’s own finance expert, Peter Kind, who initially pointed out the challenges posed to utilities by DERs<sup>15</sup> and more recently authored a paper on grid modernization that argues against fixed charges. Kind writes:

“Adopting meaningful monthly fixed or demand charges system-wide still reduce financial risk for utility revenue collections for the immediate future, but this

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<sup>13</sup> Peskoe, p. 16

<sup>14</sup> *Munn v. Illinois*, 94 U.S. 113 1877

<sup>15</sup> Peter Kind, “Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business,” Edison Electric Institute. January 2013.

approach has several flaws that need to be considered when assessing alternatives.

Fixed charges:

- do not promote efficiency of energy resource demand and capital investment
- reduce customer control over energy costs
- have a negative impact on low- or fixed-income customers; and
- impact all customers when select customers adopt DERs and potentially exit the system altogether, if high fixed charges are approved and the utility's cost of service increases"<sup>16</sup>

Kind goes on to say that "it is clear from the recent regulatory actions reconfirming support for DERs and net energy metering that policymakers are interested in DER development and customers want the option to choose their own energy supply."

In addition, state regulatory commissions have historically rejected the notion that the costs of maintaining the utility's distribution system should be included in the marginal costs attributable to individual customers for ratemaking purposes. As the Washington Utilities and Transportation Commission stated in a 1989 decision, including the costs of a "minimum-sized" distribution system in customer-related costs would "lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers." The Commission concluded: "Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum sized distribution system is not."<sup>17</sup>

Indeed, many economists share the view of the Washington Commission that only the customer-specific metering and billing costs should be considered truly fixed and thus recovered through fixed charges. "[T]he mere existence of system-wide fixed costs doesn't justify fixed charges," says University of California Professor Severin Borenstein. "We should use fixed charges to cover customer-specific fixed costs."<sup>18</sup>

Although this paper does not recommend a particular rate design or structure, rates that empower customers to control their energy costs and adopt new technologies while sending price signals that reduce system costs can provide benefits to all ratepayers. For example, in California, time-of-use (TOU) rates have been adopted as a feature of a new NEM tariff to incent solar customers to shift load to times of peak demand. Likewise, Peter Kind recommends TOU as an important tool "in optimizing system capacity and moderating incremental capital investment in electric energy infrastructure."

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<sup>16</sup> Peter Kind, "Pathway to a 21<sup>st</sup> Century Electric Utility," Ceres. November 2015.

<sup>17</sup> Cause U-89-2688-T, Third Supp. Order, P. 71

<sup>18</sup> See Borenstein, "What's so Great about Fixed Charges?" Energy Institute at Haas, November 3, 2014. <https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/>



On the other hand, while EEI notes that demand charges have “been widely used in the industry” and suggests they may be applied to residential customers,<sup>19</sup> there is little evidence that doing so would produce benefits. Unlike industrial customers, residential customers have diverse loads that impose distribution system costs only in aggregate. A recent paper by the Rocky Mountain Institute concluded: “Our review finds that there is comparatively little industry experience with mass-market demand charges relative to time-based rates,” the report said. “Limited empirical evidence is available to provide insight on the efficacy or impact of demand charges on any desired outcome beyond cost recovery.”

In considering rate design principles, we encourage commissioners to review the Regulatory Assistance Project’s 2015 handbook, “Smart Rate Design for a Smart Future,” which includes the following principles:

1. **Universal Service:** A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
2. **Usage-based Pricing:** Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
3. **Fair Compensation:** Customers who supply power to the grid should be fairly compensated for the full value of the power they supply.

#### **4. Utility Business Model Reform is Foundational to Rate Design**

Unlike unregulated industries, where companies have a financial incentive to reduce fixed costs in order to maximize profits in the face of competition, regulated utilities have the opposite incentive: the more fixed infrastructure the utilities build, the more profit their shareholders earn from their ratepayers. This “cost-of-service” ratemaking structure was well-suited to solving the challenges of an earlier time in the industry’s history, when it was imperative for utilities to build out infrastructure and expand essential and reliable service across their territories.

Now that universal service has largely been accomplished, however, it is clear that the traditional cost-of-service ratemaking is at odds with a number of important policy goals. For example, while policymakers may wish to encourage conservation to keep total electric system costs low, cost-of-service ratemaking motivates utilities to continuously seek new infrastructure investments and to centralize all energy investment within the utility. This type of perverse incentive can result in the trend shown in Figure 2, where utility rate base continues to increase even as consumption remains flat.

In addition, the traditional business model might do little to ensure other goals – including improved customer service, reliability, and safety – are met. In light of the emergence of new technologies capable of reducing energy consumption and providing grid services on the customer side of the meter, regulators now need to consider whether the traditional utility business model should be adjusted.

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<sup>19</sup> See EEI Primer Section II a.

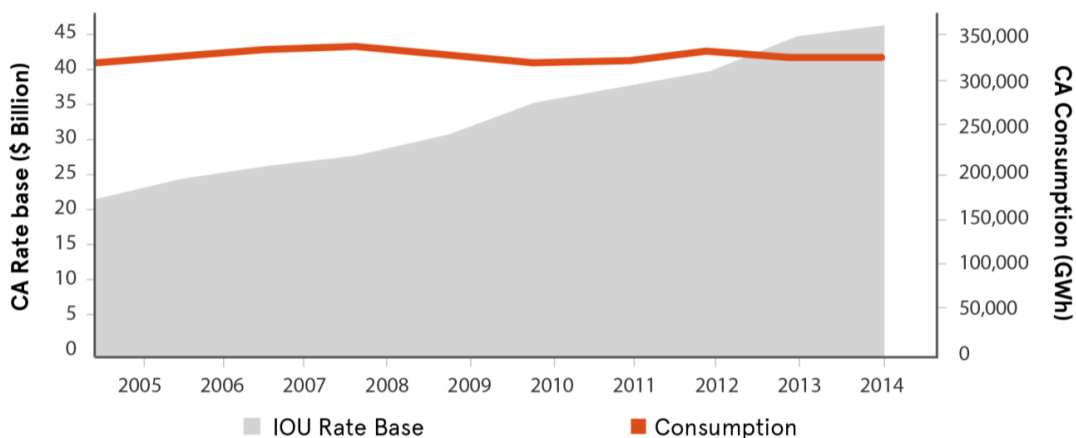


Figure 2: Trends in rate base for California investor-owned utilities<sup>20</sup>

#### 4.1. DERs Should be Included in Long-Term Planning

Rooftop solar, smart inverters, battery storage, controllable appliances, networked EV chargers, and other distributed energy resources are quickly forming the basis of a modern, interconnected electric grid. These resources not only provide value to their owners, but they also have enormous potential value to the electric grid if they are appropriately incorporated into grid planning and operations.

Rather than seeking to suppress customers’ demand for customer-sited DERs through rates that purport to reflect cost-causation, utilities should incorporate them into their long-term planning activities. If correctly planned for and incentivized, DERs can fill the need for both generation and distribution system investments, potentially creating significant cost savings that can reduce electricity system costs for all ratepayers.

Moreover, DERs might be better suited to meet some grid needs than traditional utility investments, which often have the quality of being “lumpy,” meaning a single large investment is made now to meet future projected load growth going out decades. If the load growth does not materialize, that investment can become a stranded cost borne by all ratepayers. Even if the load growth does materialize, a single large investment made today to meet a need that may not arrive for a decade imposes an inter-generational subsidy on current ratepayers.

By contrast, customer-sited distributed resources are “modular,” meaning they can be deployed gradually in very small units and geographically targeted to meet needs as they arise. Not only does this reduce the risk of stranded assets, but it also avoids the lost time-value of money associated with large lumpy investments. Just as the Vermont Public Service Board establishes geographical emphasis for energy efficiency, a forward-thinking regulator may consider geographical emphasis for other DERs.

<sup>20</sup> “Electric and Gas Utility Cost Report: Public Utilities Code Section 747 Report to the Governor and Legislature”, California Public Utilities Commission, April 2015; and “Energy Almanac,” California Energy Commission, 2005-2014

Integrated Resource Planning activities can be a good way for utility planners to identify specific locations where distributed resources can defer planned distribution, transmission, and generation investments. Concerns about cost-shifting can be greatly reduced if utility regulators take an active role in using distributed resources to reduce total system costs. Nevertheless, regulatory planning exercises are likely not sufficient alone to overcome the utility's inherent bias toward infrastructure that can be owned and rate-based.

#### **4.2.Revenue Decoupling Could be Implemented**

Revenue decoupling is a ratemaking technique that has been used for several decades to promote energy efficiency and conservation by “disconnecting” electricity sales from utility shareholder profits. So far, 15 states have implemented revenue decoupling for electric utilities, and eight more are considering it.<sup>21</sup>

In states where revenue decoupling has not been implemented, utility revenue that is lost through energy efficiency, conservation or self-generation directly reduces utility shareholder profits, and utilities in these states are much less likely to promote such measures. For example, in Nevada, where electric decoupling has not been implemented, the incumbent monopoly utility, NV Energy, successfully lobbied the state PUC to implement draconian changes to net metering that have eviscerated the state's rooftop solar industry.<sup>22</sup> Thus, as a first step to aligning the utilities' profit motive with public policy goals promoting efficiency, conservation and self-generation, policymakers may consider revenue decoupling for utility ratemaking.

#### **4.3.Cost-of-Service Ratemaking Should be Re-Examined**

Utility regulators have long been aware of the utilities' perverse incentive to sell more electricity, which often clashes with the goals of keeping utility bills low and reducing pollution. In order to better align energy pricing with the broader societal and ratepayer goals, regulators have sought to implement policies that incent customers to conserve energy and reduce utilities' incentives to sell more power. These measures include revenue decoupling, volumetric energy pricing, inclining block tiered rates, utility energy efficiency incentives, and prohibitions on utility ownership of generation. All of these policies can benefit the public, but all run the risk of adversely affecting utility earnings unless appropriate changes are embraced in the regulatory framework.

The advent and commercialization of DERs like rooftop solar, battery storage, smart inverters, and other connected devices creates an even greater impetus to reevaluate and adjust the utility business model. The possibility of resources located on the customer side of the meter that can provide energy, capacity, ancillary services, transmission and distribution deferral, and other values creates the need for a new utility revenue mechanism that removes the natural preference for utility-owned investments over customer-owned resources that can provide the same service at a potentially lower cost.

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<sup>21</sup> Brookings Institute: “Rooftop solar: Net metering is a net benefit,” by Mark Muro and Devanshree Saha.

<sup>22</sup> *Ibid.*

It is for this reason that New York and California have both opened proceedings to examine the utility business model and explore ways to reduce system costs by using customer-sited resources to defer utility infrastructure investments. Although differing in their approach, both states' efforts seek to answer the primary question facing regulators in light of the rise of DERs:

How can the utility be properly incented to rely on customer-sited resources to meet infrastructure needs in instances where such resources would be less expensive to procure than traditional utility investments?

California Public Utilities Commissioner (CPUC) Mike Florio summarized the problem and the need for utility business model reform in a recent CPUC ruling that proposes to compensate utilities when they use DERs to defer traditional infrastructure projects.<sup>23</sup> "If the utility displaces or defers such investments by instead procuring DER services from others, it earns no return on the associated expenditures — such operating expenses are merely a pass-through in rates," Florio wrote. "Thus, asking the IOUs to identify opportunities for such displacements or deferrals, as we are doing in this proceeding and the [distribution resource planning proceeding], sets up a potential conflict with the company's fundamental financial objectives."

## 5. Conclusion

Distributed Energy Resources bring much needed technological innovation, competition, and customer engagement to the utility sector, and the benefits of these resources to both participating and non-participating ratepayers is likely to be substantial. Thus, regulators should not adopt a one-size-fits-all approach to rate design, but should instead devise solutions that are appropriate for ratepayers and also appropriately reflect state and federal energy policy goals, including:

- **Studying the impacts:** States should conduct a rigorous independent cost-effectiveness study to determine whether distributed solar under current rate structures imposes a net benefit or a net cost on all of their ratepayers and how distributed solar impacts total system costs. Policymakers can play an important role by seeking to standardize which costs and benefits are considered and how they are evaluated.
- **Modernizing utility planning:** Regulators should seek ways to incorporate solar and other DERs into utility planning so that these resources can be used to defer traditional infrastructure investments and reduce total system costs. Integrated Resource Planning and Distribution Resource Planning processes can be an effective way to accomplish this.
- **Updating utility business models:** States may consider implementing revenue decoupling, in addition to more extensive changes to utility business models and revenue mechanisms in order to provide an incentive for utilities to rely upon customer-sited DERs to meet infrastructure needs.

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<sup>23</sup> "Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment." California Public Utilities Commission, May 4, 2016.  
<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K702/159702148.PDF>

- **Implementing technology standards:** States may wish to consider implementing technology standards developed by national or international standards-making bodies, programs, and best practices to enhance the value of the resources. For example, at 5% solar PV penetration, a state may wish to mandate solar smart inverters that can provide reactive power and voltage control as a condition of interconnecting under the NEM tariff.
- **Encouraging choice:** Regulators should design electric rates to encourage customers to choose distributed generation and foster emerging technologies that have the potential to reduce electricity costs and environmental impacts. For example, time-of-use rates can encourage customers to adopt energy storage or load-shifting technologies capable of reducing the need for central generating capacity and distribution system upgrades.
- **Gradualism, grandfathering, and predictability:** Rate changes, if deemed necessary, should be introduced gradually so that sellers of retail energy services have a stable business climate in which to operate. Existing customers should be grandfathered into pre-existing rates so as not to destroy the value of systems already installed and any new rates should be stable and predictable to ensure that customer investments can lock-in value for the life of the system.

Finally, regulators should design rates with an eye to the benefits of emerging technology and competition in the utility space. With little competition over the past 100 years, monopoly utilities have had little incentive to innovate, and the technologies used to generate and transmit electricity have changed little during that time. The emergence of distributed energy resources offers the promise of a cleaner and more competitive electric industry, providing consumers with the benefits of innovation and efficiency that accompany competitive markets. Regulators should resist allowing incumbent monopolies to use rate design as a means to squelch innovation and stifle customer choice.