BEFORE THE
STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: REVIEW OF THE	**)**	
NARRAGANSETT ELECTRIC COMPANY	**)**	
D/B/A NATIONAL GRID – REVIEW OF	**)**	**DOCKET NO. 4568**
ELECTRIC DISTRIBUTION DESIGN	**)**	
PURSUANT TO R.I. GEN. LAW §39-26.6-24	**)**	

DIRECT TESTIMONY
OF
SCUDDER H. PARKER

SUBMITTED ON BEHALF OF
THE RHODE ISLAND
ENERGY EFFICIENCY AND RESOURCE MANAGEMENT COUNCIL

OCTOBER 23, 2015

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I. INTRODUCTION

National Grid (the "Company") has filed, in Docket #4568, a "Review of Electric Distribution Rate Design." The opening of this Docket and the filing of the rate design were required in the Renewable Energy (RE) Growth Program (REG) legislation (R.I.G.L. §39-26.6), enacted in 2014. In filing this rate design, the Company appears to have complied with the technical requirement of the law (39-26.6-24), that its proposal be revenue neutral. Nevertheless, in light of the criteria specified in §39-26.6-24 (b) to guide Public Utility Commission ("PUC") review, it is the Energy Efficiency and Resource Management Council's ("EERMC") recommendation that the rate design not be approved. This testimony is provided in support of said recommendation.

II. QUALIFICATIONS

Q. Please state your name and business address.

A. I am Scudder Parker. My business address is the Vermont Energy Investment Corporation, 128 Lakeside Avenue, Suite 401, Burlington, VT 05401.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Rhode Island Energy Efficiency & Resource Management Council.

Q. Mr. Parker, by whom are you employed and in what capacity?

A. I work for Vermont Energy Investment Corporation (VEIC), 128 Lakeside Avenue, Suite 401, Burlington VT, 05401. I am the Senior Policy Advisor in the Policy & Public Affairs Division.

Q. Please summarize your work experience.

A. I have worked on energy policy, energy efficiency, and renewable energy development since 1981. I was a Vermont State Senator for eight years in the 1980s, and from 1985-1988 was chair of the Vermont Senate Finance Committee. That committee had jurisdiction over utility policy, tax policy, and many other financial and regulatory matters.

From 1990 until 2003, I was Director of the Energy Efficiency Division of the Vermont Department of Public Service (now the Vermont Public Service Department, "PSD," or "Department"). I was responsible for overseeing the development and implementation of energy efficiency programs by Vermont energy utilities. I worked in early collaborative efforts to design demand side management (DSM) programs. From 1994 until 2003, I spent a significant portion of my time at the Department working on renewable energy policy and energy efficiency program development. I helped secure and administer grants for innovative energy efficiency programs, wind development, farm methane generation, biomass energy development, and solar initiatives.

I worked in the Vermont General Assembly on many issues for the Department. I led Vermont's effort to design and implement net metering legislation, an innovative residential building energy efficiency code, programs to provide effective efficiency services to low-income Vermonters, and adoption by Vermont of certain appliance efficiency standards. I played a leadership role in Vermont Public Service Board Docket No. 6290, relative to distributed utility planning. That docket laid the groundwork for Vermont's use of efficiency and distributed generation investments as part of a "least-cost" approach to distribution and transmission planning.

I joined VEIC in 2008, initially as a Managing Consultant in its Consulting Division. From 2010 to 2013, I was Director of VEIC's Consulting Division. I was appointed Director, Policy in 2013. Since January 2015 I have worked part-time for VEIC as Senior Policy Advisor. A current copy of my resume is appended to this testimony as Exhibit No. EERMC-SP-1.

Q. Describe your Policy Director work at VEIC.

A. In my capacity as Policy Director, my responsibilities at VEIC were primarily to shape policy direction and foster innovative approaches to increasing the economic and environmental benefits of reduced energy use. I was (and continue to be) involved in fostering aggressive implementation of energy efficiency and distributed resources in ways that empower customers to manage their energy use effectively, reduce their energy costs, provide benefits for the energy system, and yield significant societal benefits.

Q. Have you provided expert testimony as part of your professional work?

A. Yes. When I was Director of Energy Efficiency at the Vermont PSD, I frequently testified before the Vermont Public Service Board in rate cases, Integrated Resource Plan review proceedings, and in many other dockets having to do with energy efficiency program design and implementation in Vermont.

In my work at VEIC, I have filed testimony in Ontario (2008) regarding attainable levels of efficiency, and I testified in Iowa (2007-2008) in a proceeding reviewing a proposed new coal-generating facility, arguing that efficiency could more cost effectively meet the projected needs that the plant was being proposed to serve.

Q. How long, and in what capacity, have you worked in Rhode Island?

A. VEIC, along with its partner firm, Optimal Energy (together, the "Consultant Team"), have provided consultant services to the EERMC since 2008. We were hired through a competitive solicitation to provide expert assistance to the EERMC in carrying out its assigned functions under RIGL §42-140.1. Since 2008, I have co-led the Consultant Team with Mike Guerard of Optimal Energy, who is based in Providence, RI. The Consultant Team has worked closely with the EERMC throughout this period, and has worked in close coordination with the Rhode Island Office of Energy Resources (OER), National Grid, and many of the other parties involved in providing Rhode Island with least-cost energy resources.

The Consultant Team has been deeply involved in the evolution and oversight of Rhode Island's nation-leading acquisition of energy efficiency resources. This activity has taken place in large part through National Grid's energy efficiency efforts.

Of particular interest to this proceeding, I have worked closely with National Grid in the design and development of a successful pilot program that uses targeted energy efficiency resources and load control, and now, the installation of solar measures to help defer upgrades to a substation in Tiverton / Little Compton. This System Reliability Procurement (SRP) program is a part of Rhode Island's Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006 ("2006 Comprehensive Energy Act"), which established a comprehensive utility energy policy that explicitly and systematically requires maximization of ratepayers' economic savings through investments in system reliability and least-cost procurement.

Q. Have you previously testified before the Rhode Island Public Utilities Commission?

A. Yes. I have testified regularly in proceedings in Rhode Island, including Annual Energy Efficiency Program Plan and System Reliability Procurement review proceedings, Triennial Energy Efficiency and System Reliability Plan review proceedings, proceedings reviewing proposed targets for energy efficiency savings, and proceedings establishing the Standards for Energy Efficiency and Conservation Procurement and System Reliability.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to outline my review of, and to present my conclusions regarding, the rate design proposed in the filing by National Grid in Docket 4568**,** on behalf of the EERMC.

Q: **Please present your main conclusions.**

A: The rate design proposed in the filing by National Grid in Docket 4568 would be likely to have a somewhat negative impact on the adoption of and benefits received from energy efficiency efforts by Rhode Island ratepayers. National Grid's claim that the rate design would give customers an incentive to manage the level and timing of their use is flawed, because there is no enhanced customer access to actionable information about how their level and timing of use would affect their bills. The Company is clear that this proposal does not include any planning or investment strategy to enhance that capability for customers or the utility.

In an era of growing distributed resource options for customers and utilities, the proposed rate design does not appropriately reflect the opportunity to manage loads and secure benefits from customer resources. It ignores completely the potential benefits that distributed resource investments by customers could provide to the system. The proposed design could actually punish customers for activities that the Company appears, in principle, to support.

A different approach to addressing the challenges posed by substantial new distributed generation (and distributed resource deployment more generally) is technically feasible, and could provide significant increased benefits, while still helping the Company realize its objective of fairly recovering distribution system costs. An alternative approach that is consistent with Rhode Island's overarching legislative guidance could actually enhance the implementation of the REG program, and capture increased benefits for participants, customers, and the state. The statute requiring the rate design filing recognizes this possibility.

The REG legislation should be considered as consistent with and supplementary to Rhode Island's 2006 Least Cost Procurement and System Reliability legislation. Therefore, it might be a constructive step to expand the current discussion into a broader consideration of the larger issue: Perhaps it is time for National Grid to invest in a modern, dynamic, customer-partnered distribution system that can fairly track, reflect and secure the real costs and benefits customer investments can (or could) provide.

III. SCOPE OF TESTIMONY

Q. Please describe the aspects of National Grid's rate design proposal you will address in your testimony.

A. My testimony addresses primarily the proposal by the Company to impose a fixed distribution charge for Residential Rate A-16 and small Commercial and Industrial (C&I) Rate C-60.

Q. Please describe the rate structure proposed by National Grid.

A. As National Grid states: "The Company's proposed rates will reduce the amount of its revenue requirement recovered through variable (per kilowatt-hour) charges and increase the amount recovered through customer and/or demand (per kilowatt) charges…" (Letter of Transmittal July 31, 2015, p.2)

National Grid proposes to do this by assessing a "tiered" demand rate structure. "The rate structure for Residential Rate A-16 and Small Commercial and Industrial (C&I) Rate C-06 includes tiered customer charges." (Letter of Transmittal, p. 2) The proposed rate design includes a provision that the customer's highest-use month would determine what tier the customer is in, and that tier would be in effect for the succeeding twelve months.

Q. Are there any sections of the filing that you do not address in detail?

A. Yes.

The Company proposes an "access fee" that would apply to the owners of Stand-Alone Distributed Generation (DG) accounts. It also proposes to consolidate Large Demand Rate G-32 and Optional Large Demand Rate G-62. I do not directly address these features of the Company's proposal in my testimony.

In this filing, the Company does not propose changes to the Low Income Rate A-60, but does state that it "…will consider the appropriate design of the rates for this class in the Company's next electric distribution case." (Letter of Transmittal, p. 2). Since there is no specific proposal, I do not address this possibility, though, based on my comments below, a tiered structure applied to this customer class would warrant close scrutiny.

Q. So your testimony addresses primarily the effects of the proposed rate design on Residential and Small Commercial customer classes?

A. As to the question of direct impact on customers, that is true. It is reasonable to conclude that the primary effect of this rate design will be experienced by Residential A-16, Rate C-06, and Stand-Alone DG customers. These effects will be experienced both by customers who participate in net metering or who are part of the REG program, and by customers who are not. I also address the policy implications of the approach the Company has taken.

Those comments go beyond the rate classes on which I focus most of my attention.

IV. IMPACTS OF PROPOSED RATE DESIGN ON ENERGY EFFICIENCY EFFORTS IN RHODE ISLAND

Q. What do you believe would be the effect of the rate design proposed by National Grid in Docket 4568 on customers in Residential Rates A-16, and Small Commercial and Industrial Customers in Rate C-06?

A. The proposed rate design would be likely to have a somewhat negative impact on the adoption of and benefits received from energy efficiency efforts by the participating Rhode Island ratepayers. (These efforts to promote efficiency are being implemented by National Grid under Rhode Island law as part of Least Cost Procurement.)

Q. Please explain why you think this would be the case.

A. The proposed rate design will have a limited, but generally negative, impact on customer savings from energy efficiency investments, since customers would be paying more in fixed (that is, only occasionally changeable) kW charges. This means customers will receive less benefit from each unit of efficiency savings.

Q. National Grid asserts that the impact on the average customer (increase or decrease in bills) will not exceed a 5 percent increase or decrease in monthly bills. Does this mean that any potential impact from this change in rate design will be small?

A. In general, for the present customer profile, to the best of my knowledge and drawing on my experience, it is my opinion that the impact will be relatively low. However, the *potential* negative impact of the current proposal could be significant. Although National Grid indicates that it does not believe at this time that any customer would experience negative impacts of the highest potential magnitude, National Grid's presentation at the Technical Session held in this Docket on September 17, 2015, offered a table illustrating that theoretically possible bill impacts could be as high as 34.1 percent in Tier 2, 43.1 percent in Tier 3, and 50.4 percent in Tier 4 (National Grid Presentation, p. 23).

Q. Should ratepayers be concerned about this "theoretical" potential impact?

A. Yes, they should. The proposed rate design could, across a year or more, seriously punish individual customers who have only one month of high use, whatever its cause, or however unlikely it is to be repeated. I am not aware of any recourse National Grid might propose for customers in such a situation. This "ratchet" effect could have a disproportionately negative impact on low- and moderate-income customers, and on small commercial businesses operating on a narrow margin.

Q. Are there other reasons you are concerned, even if the actual immediate impact is likely to be small?

A. Since this proposal charts a new direction for the Company's rate design for these customer classes, possible future variations of the design deserve consideration in this proceeding.

National Grid suggests (in its response to Data Request CLF 2-5) the possibility that the framework of this rate design could be used to increase the percentage of distribution costs recovered through fixed charges ("customer and demand charges") over time from 40 percent (the immediate effect of this proposal) to as much as 100 percent in the future. That change would significantly increase the negative impacts on and the potential risks to residential and small commercial customers. I have not performed any calculation of the potential increased risk or level of impact from such proposals, and National Grid's statement in this response obviously lacks the necessary specifics for accurately assessing either the risk or the impact. It is not unreasonable to assume that such a level of recovery from a fixed-cost structure could increase the likelihood and potential size of the impacts outlined by the Company in the table it presented at the Technical Session cited above. Any further proposal to increase the tiered demand charge that is accompanied by a proposal to lower the variable charge (as has been proposed in several jurisdictions) would provide a significant negative impact on energy efficiency program efforts.

V. THE PROPOSED RATE DESIGN IS NOT AN EFFECTIVE "DEMAND MANAGEMENT" DESIGN

Q: Is National Grid's claim creditable that the rate design would give customers an incentive to manage the level of use?

A. No, it is not. National Grid makes this assertion in its Letter of Transmittal (p. 2) and in its testimony (Zschokke and Lloyd, p. 35, lines 13 through 18). The Company asserts that the tiered design will give customers an incentive to move to a lower tier through "…aggressively managing their usage or implementing energy efficiency measures" (Zschokke and Lloyd, p. 35, line 18).

The assertion that this rate design is a form of demand charge that will effectively guide customer behavior is not creditable, because National Grid does not offer enhanced customer access to meaningful information about how customers' level and timing of use would affect their bills. This lack of access to information prevents customers from being able to take action to "aggressively manage" their electricity use.[1] The Company is clear that this rate design proposal does not present any planning or investment strategy to enhance that capability for customers or the utility. (Zschokke and Lloyd, p. 37, line 13, through p. 38, line 11; see also Response to CLF 2-5).

Further, in response to Division 1-8, the Company clarifies that the proposed rate design:

> *"…will not necessarily encourage customers to shift load from high use, peak periods into low use, off-peak periods because the proposed design, unlike the ideal design does not have a direct demand component. Rather, the Company's proposal is intended to encourage customers to reduce, or constrain, overall use during high-use months. Reducing customer use during high use months will result from customer management of demand and, since the ratio of peak to total use would be reduced, accomplish the goal of better system utilization."* (Response to Division 1-8).

[1] It is important to note that it is not simply the presence of meters that will facilitate benevicial customer load shapes, it is analysis by the company of costs and benefits, of usage at particular times, and the reflection of those costs and benefits in a more granular rate design

In other words, customers will have to work hard to: (1) determine what might be a "peak month"; (2) make an extra effort to reduce load in that peak month, without any ability to track how they are succeeding at that effort; and (3) do this by managing total electric use, not peak use, throughout the month. This might or might not result in what the Company claims to be a very small total effect on customer bills.

On the risk side of the ledger, a sudden, significant increase in use during any given month (for whatever cause) could lock the customer into significantly higher bills for the succeeding twelve months.

VI. THE PROPOSED RATE DESIGN DOES NOT APPROPRIATELY REFLECT THE OPPORTUNITY TO MANAGE LOADS AND SECURE BENEFIT FROM CUSTOMER RESOURCES

Q. What are your conclusions about the purpose and design of this proposal?

A. The proposed rate design is primarily focused on ensuring National Grid's consistent recovery of distribution fixed costs from customers, not on advancing a new design that will empower customers and enhance system benefits.

Despite its tiered structure, the proposed rate design will not be an effective strategy for informing customers about the timing, or time-related impacts, of their energy use. This design therefore does not fit, nor is it a generally accepted variation on, the standard definition of a "demand response" rate structure. In other words, the complexity of the tiered system, the lack of good customer information, and the generally small effect on bills will make it unlikely that this design actually drives positive change in customer behavior. At the same time, it increases the risk for significant, sudden increases in customer bills that are not likely to be understood or easily addressed by customers.

National Grid's witnesses testify repeatedly to the Company's hope for an innovative new energy future:

> *"These examples demonstrate the need to recognize three significant facts: the distribution system must evolve to manage significant two-way power flow; the distribution system and the customers must work together to research and develop ways to integrate customer-sided resources into operation of the distribution system to access value on the system from these resources, when feasible, for both parties; and pricing to recover the*

costs of the integrated system will need to evolve to recognize the changing nature of the connecting customer." (Zschokke and Lloyd, p. 16, lines 12-18)

Again, the witnesses outline how changing times of use might provide system benefits:

"As customers improve their individual load pattern through use of demand side management activities, system and distribution system utilization will improve. Encouraging customers to shift load from high use, peak periods into off-peak periods results in a better utilization of the existing distribution system and other elements of the electric system by reducing the number of hours that the distribution system must be available to serve peak loads. Theoretically, the utilization across all hours could reach very high and consistent levels. If achieved, there would be less need for time differentiation of demand charges or energy rates. (James C. Bonbright. Principles of Public Utility Rates (1st ed. 1961). Any consideration of rate design and its stability over time must consider this possibility. Better utilization of the system also reduces the need to build additional system capacity to meet peak loads that occur for as few as 20 to as many as a few hundred hours per year." (Zschokke and Lloyd, p. 20, line 15 through p. 21, line 5)

However, this proposal does not advance that future. And it does not facilitate attainment of Bonbright's apparent desired outcome. National Grid discusses a brave new world, and then consigns customers (who might well have new costs imposed on them) to the electric equivalent of "dial-up" service in the digital age.

The tiered structure of the rate design is intended to avoid the arbitrary nature of a single, large, and unchanging increase in fixed costs. The attempt is well intentioned, but its efficacy unproven. Its mitigation of the potential negative impact of such a design would be only partial, and might be of very little effectiveness.

The Company proposes relying on a program of education and outreach to inform customers and encourage energy changes to avoid cost increases. The design of such an effort, its cost, and an assessment of its likelihood for broad acceptance and success are not addressed in the filing. It is also not clear whether these costs would be proposed as part of Least Cost Procurement.

VII. A DIFFERENT APPROACH IS FEASIBLE AND SHOULD BE CONSIDERED

Q. Is it your assertion that the proposed rate design is grounded in an outdated model of how costs are created by customers, and largely ignores the potential benefits that distributed resource investments by customers could provide to the system?

A. Yes, it is.

Q. Please elaborate.

A. I am not an expert in rate design. I am an expert in least-cost procurement, and I have deep experience with customer-side resources that involve energy efficiency and distributed generation (including distributed renewable generation and combined heat and power). I consider customer demand response and load-shaping through storage and controls to be increasingly important resources that should be pursued as part of Rhode Island's System Reliability and Least Cost Procurement efforts.

There is a growing body of literature and practice that recognizes the significant potential for these "distributed resources" to help shape a new energy system. It seems (as seen in the extracted material, above) that National Grid is also aware of this emerging possibility.

In addition, I have been increasingly impressed with the potential for actual expansion of electricity use in some applications that hold promise for providing significant environmental and economic benefits. The two most obvious of these are cold-climate heat pumps (which can provide both increased cooling efficiency and lower-cost heating) and electric vehicles. These technologies are relevant to this proceeding. That is, in addition to potentially increasing electricity use and thus contributing to electricity sales, they also lend themselves well to demand management and load control.

As I continue to conduct my own research and investigation into the potential of these emerging customer options, I have come across two papers that are timely and valuable resources that could inform this proceeding. Both have been published very recently. The first is "Smart Rate Design for a Smart Future" by Jim Lazar and Wilson Gonzales (Montpelier, Vermont: Regulatory Assistance Project), July 2015. **http://www.raponline.org/document/download/id/7680**. I submit this document as Exhibit No. EERMC-SP-2. The second is, "The Economics of Demand Flexibility: How 'Flexiwatts' Create Quantifiable Value for Customers and the Grid," by Mark Dyson and James Mandel (Aspen, Colorado: Rocky Mountain Institute), August 2015. **http://www.rmi.org/electricity_demand_flexibility**. I submit this document as Exhibit No. EERMC-SP-3.

Q. Do you propose these papers as part of an alternative rate design in this proceeding?

A. No, I do not. I propose them because they provide substantial evidence that there are thoughtfully articulated, alternative ways to design rates that would actively support the goals of the Rhode Island Renewable Energy Growth legislation and other state policies and at the same time afford appropriate recovery of distribution costs. As Lazar and Gonzalez note:

> *For most of its history, the electric utility industry saw little change in the economic and physical operating characteristics of the electric system. Though the system provided reliable and low-cost service, little in terms of system status or customer use was known in real or near real time. For an industry in the information age, parts of the electric system can be considered rather "unenlightened."*
>
> *Current advancements in technology will have marked impact on current and future rate designs. First, end-users (i.e. customers) are installing their own generation, mostly in the form of photovoltaic (PV) systems, and are connecting different types of end-use appliances with increasing "intelligence" built in; electric vehicles (EVs) , too are poised to grow rapidly as a whole new class of end-use, just as storage systems are poised to become economic. Second, utilities are deploying advanced metering and associated data systems, sometimes referred to as advanced metering infrastructure (AMI) or smart meters, and more sophisticated supervisory control and data acquisition (SCADA) systems to monitor system operations. To realize the full potential of these new systems and end-uses, regulators, utilities, third-party service providers, and customers will need to utilize more advanced rate designs than they have in the past.*
> (Lazar and Gonzalez, p. 5).

Q. Why is this relevant to a proceeding in which National Grid is simply (as instructed in law) providing a revenue-neutral rate design?

A. Because the design of the rates matters. It matters right now. Again, quoting from Lazar and Gonzalez:

> *Rate design is the regulatory term used to describe the pricing structure reflected in customer bills and used by electric utilities in the United States. Rate design is not only the itemized prices set forth in tariffs; it is also the underlying theory and process used to derive those prices. Rate design is important because the* ***structure*** *of prices—that is, the form and periodicity of prices for the various services offered by a regulated company—has a profound impact on the choices made by customers, utilities, and other electric market participants. The structure of rate designs and the prices set by these designs can either encourage or discourage usage at certain times of the day, for example, which in turn affects resource development and utilization choices. It can also affect the amount of electricity customers consume and their attention to conservation. These choices then have indirect consequences in terms of total costs and benefits to society, environmental and health impacts, and the overall economy.* (Lazar and Gonzalez, p. 5, emphasis in the original).

I am concerned that National Grid seeks to establish in this proceeding a rate structure that it will then carry forward into the "new future" it hints at. The problem with establishing that precedent is that it could well restrict innovation; fail to account for value created (or value potentially available) from distributed resources; and might actually inhibit investments that could add environmental, economic, and system value. At a time when far more granular rate designs could *both* recover costs *and* promote innovation, the Company's approach, as proposed, would create lost opportunities. Lazar and Gonzalez address rate design proposals of the type presented by the Company in this proceeding directly:

> *A few rate analysts have recommended that demand charges be extended from large commercial customers (where they are nearly universal) to small commercial and residential customers. Some of these analysts suggest this is an appropriate way to ensure that solar customers contribute adequately to system capacity costs. This option is inapt for most situations for several reasons. The only distribution system component sized to individual customer demands is the final line transformer. The relatively small portion of cost of service represented by the line transformer required to serve solar customers amounts to only*

> *about $1/kW/month. In addition, the diversity of customer demand at any given time of the day, and the lack of understanding of the potentially complex concept, suggest against this option.* ***Time-differentiated prices can more equitably recover costs that are actually peak-oriented from all customers, including solar customers.*** (Lazar and Gonzalez, p. 9, emphasis in the original).

Q. Please provide an example of the kind of problems the current proposal might create, even for a customer without a solar installation.

A. Let us suppose a customer purchases an electric vehicle. Under both the current and the proposed rate design, that customer has no incentive to charge the vehicle at off-peak times. Charging during off-peak times is a "good" for a utility because it contributes to flatter load shapes, lessening the strain on the distribution system, especially during peak hours. Under the proposed rate design, things actually get worse. The customer would increase electricity use, perhaps significantly, in a way that *could have been* managed to the benefit of the system by the Company. Instead, the customer would receive no positive price signal as to when to charge, *and* the customer could easily be moved up into a higher tier through increased electric use. This would increase the customer's bill by more than just the unit charge for electricity consumed. Further, the utility would lose an opportunity to increase its system utilization, and the customer would be penalized for making what should be a societally positive choice.

In a similar manner, under both the current rate design and in the proposed design, ordinary customers have no incentive to purchase and manage the "smart appliances" referred to by Lazar and Gonzalez. Why invest in intelligent appliances if there is no reward or incentive for using electricity in off-peak hours? In the jargon of energy efficiency, choices by customers to forgo these opportunities are considered "lost opportunities." That is, an opportunity exists for a small, incremental cost to provide significant benefit at the time of purchase. Retrofit and "retooling" at a later date will be more costly.

As customers increasingly choose to install heat pump technologies (whether originally for summer cooling or winter heating) the effect of increased customer electric use to offset fossil fuel heating could easily result in customers moving to a higher tier. An opportunity for using this technology could be to help those customers use the heat pumps at times that do not coincide with seasonal (or other critical distribution) peaks on the system. In this way, beneficial electric use could be increased but its time of use managed so that the increase does not result in new system costs. The proposed rate design enhances the likelihood of the negative impacts for customers, and offers no incentive for the potential up-side.

Ironically, the failure of the utility to support a smart energy grid proactively means that the only way customers can realize the benefits of these technologies is to "leave" the grid and manage their own loads. I do not think this phenomenon is imminent in Rhode Island, but it is a very real concern in California and Hawaii. This could be a very destructive direction for Rhode Island to go in, since there are generally far greater benefits and savings (for customers and utilities) to having customers stay on the grid.

VIII. PRINCIPLES TO GUIDE AN APPROPRIATE RATE DESIGN

Q. Do you consider this proposed rate design to be a just and equitable rate design?

A. No, I do not. It is my opinion that the Company would be creating a less equitable rate design, in the name of an outdated and oversimplified definition of *cost causation*.

Q. What principles would you advocate as part of a modern rate design?

A. Lazar and Gonzalez advocate for three "Principles for Modern Rate Design" that I think provide a solid starting point.

> ***Principle 1:*** *A customer should be able to connect to the grid for no more than the cost of connecting to the grid.*
>
> ***Principle 2:*** *Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.*
>
> ***Principle 3:*** *Customers who supply power to the grid should be fairly compensated for the full value of the power they supply.* (Lazar and Gonzalez, p. 6.)

In addition, Lazar and Gonzalez propose that "best practice" rate design solutions should balance the goals of:

- *Assuring recovery of utility prudently incurred costs;*
- *Maintaining grid reliability;*
- *Assuring fairness to all customer classes and sub-classes;*
- *Assisting the transition of the industry to a clean-energy future;*
- *Setting economically efficient prices that are forward-looking and lead to the optimum allocation of utility and customer resources*
- *Maximizing the value and effectiveness of new technologies as they become available and are deployed on, or alongside, the electric system; and*
- *Preventing anticompetitive or anti-innovation market structures or behavior.* (Lazar and Gonzalez, p. 8.)

These principles represent an appropriate updating of Bonbright's principles of cost causation in the new energy environment.

Q. Do you believe the proposal by National Grid reflects these principles?

A. No, I do not. In response to a question from the Division (Division 1-4), National Grid states that:

> *…compensation for net metering, long-term contracting, distributed generation standard contracts, and Renewable Energy Growth Program participants are determined by relevant statutes, Company tariffs, and PUC rules and regulations. The Company is not proposing any changes to the various methods of compensation in this proceeding, but rather will propose any appropriate changes in the dockets that are specific to each program.* (Company Response to Division Data Request 1-4, second paragraph)

It seems the Company is saying that since various legislative and regulatory structures have in some measure "prescribed" a value for renewable resources, then it is not the Company's job to identify the specific other benefits they might provide. The Company then qualifies this assertion by suggesting that in the Tiverton / Little Compton project in Rhode Island, and in the Company's Solar Phase II pilot in Massachusetts, National Grid will be able to *"…ascertain the methods to value distributed generation and to propose appropriate payments or credits to those customers who can operate the facilities in a manner to provide those values to the system."* (Division 1-4, third paragraph)

I agree with the Company that it is not reasonable—in this proceeding—to assess fully all the various costs and benefits of distributed resources. Where I disagree with the Company is in the creation of a system of cost recovery in which the utility has little ability—or frankly, little incentive—to reflect those costs and benefits with any accuracy, and with ongoing flexibility.

Q. Are the values of renewable energy generation the only point at issue in this proceeding?

A. It would appear that National Grid believes so. However, the missed opportunity to include fair valuation of all distributed resources is at issue, as well. A proposal designed simply to recover costs from distributed generation actually misses the opportunity to secure enhanced value from many more customers. This design should not be just about reliably recovering fixed costs of the system (supposedly jeopardized by distributed generators). But it should actually promote innovation, new technologies, and strategies that enhance value, and in the long run, lower costs and environmental impacts.

Instead of using this docket to propose a new rate design appropriate to this new vision of utility service, National Grid relies on a very traditional notion of cost causation and explicitly avoids the question of how the new vision of a dynamic and interactive system (for the customer classes most affected) might become possible:

> *Although the Company does offer rates with demand-based charges to its medium and large C&I customers, the Company is limited in its ability to implement demand-based rate designs for residential and small C&I customers because new, higher-cost metering necessary to measure kW is not typically installed for customers in these rate classes. In addition, significant outreach and education would be needed to provide customers with the information necessary to comprehend the advantages that demand-based rates provide to them.* (Zschokke and Lloyd, p. 22.)

Although I would agree with National Grid that the path to a new vision of the utility is not already paved, it is my opinion that using an "old approach" at a time of opportunity could be both detrimental to customers and to the long-term realization of that vision. Further, behind the creation of that rigid and arbitrary rate design is a real question about the Company's readiness to do the work of identifying and clearly providing to customers and markets the price structures that accurately reflect those costs and benefits. That is an important—perhaps essential—part of what utilities need to do as the new energy system emerges. Not doing so will likely affect customer satisfaction with their utility company.

IX. RHODE ISLAND SHOULD CONSIDER A DIFFERENT APPROACH

Q: Is a different approach to addressing the challenges posed by substantial new distributed resource availability technically feasible, and could it provide significant increased benefits, while still realizing National Grid's objective of fairly recovering distribution system costs?

A: Yes. Instead of arbitrarily increasing customer fixed costs in a way that ensures utility cost recovery, but does not advance other system benefits, National Grid could design a system in which customers would:

(i) actually know when they were using energy, and when they were creating high demand;

(ii) participate (either through time-varying rates [TVR] or through actual management of their load by the utility, within clearly defined parameters) in reducing electricity use during times of highest demand, and potentially increasing electricity use in times of lower system demand.

(iii) have their investments in efficiency, combined heat and power (CHP), distributed generation, and energy storage linked to a system and management tools that could realize benefits from timely use, non-use, release, or sustained efficiency.

Q. Is there evidence that such a design could provide system, economic, and environmental benefits?

A. Yes, there is.

The Rocky Mountain Institute ("RMI") paper on "The Economics of Demand Flexibility" begins to estimate the actual benefits of various possible scenarios for creating and managing what it calls "flexiwatts":

Demand flexibility uses communication and control technology to shift electricity use across hours of the day while delivering energy-use services

> *(e.g., air conditioning, domestic hot water, and electric vehicle charging) at the same or better quality but lower cost. It does this by applying automatic control to reshape a customer's demand profile continuously in ways that either are invisible to or minimally affect the customer, and by leveraging more-granular rate structures that monetize demand flexibility's capability to reduce costs for both customers and the grid.* (RMI, p. 5.)

In other words, distributed resource assets might also add new value to the system that are neither reflected in rates nor able to be realized under the current system. Both bill savings to the customer and system cost savings to the utility can be significant. The RMI paper performs an analysis of the potential benefits of adopting strategies of this sort:

> *…utility and customer investment on both sides of the meter are based on the view that demand profiles are largely inflexible; flexibility must come solely from the supply side. Now, a new kind of resource makes the demand side highly flexible too.* ***Demand flexibility*** *(DF) evolves and expands the capability behind traditional demand response programs. DF allows demand to respond continuously to changing market conditions through price signals and other mechanisms. DF is proving a grossly underused opportunity to buffer the dynamic balance between supply and demand. When implemented, DF can create quantifiable value (e.g., bill savings, deferred infrastructure upgrades) for both customers and the grid. Here, we analyze demand flexibility's economic opportunity. In the residential sector alone, widespread implementation of demand flexibility can save 10-15% of potential grid costs, and customers can cut their electric bills 10-40% with rates and technologies that exist today.* (RMI, p. 5; emphasis in the original.)

Q. Are you saying that these levels of savings are available for Rhode Island?

A. I am not prepared to demonstrate that they are, and that is not the purpose of my testimony. The point I want to emphasize is that the rate design proposal before us does not even contemplate an approach that would assess the potential for savings from these technologies and rate structures. National Grid is scrupulous in assuring the PUC that it is *not* proposing new investment in the intelligent grid. Although that assertion might provide some small reassurance to some in the short run, making a proposal that actually restricts the adoption of technologies and strategies that could benefit Rhode Island consumers cannot be considered a productive proposal that takes the long view.

Q: Does Rhode Island's overarching legislative guidance offer a framework that could actually enhance the implementation of the REG program, and capture increased benefits for participants, customers, and the state?

A: Yes. The statute requiring the rate design filing recognizes this possibility. The legislation directing the conduct of this proceeding contains the following guidance:

> RIGL §39-26.6-24(b) *In establishing any new rates the commission may deem appropriate, the commission shall take into account and balance the following factors:*
>
> *(1) The benefits of distributed-energy resources;*
>
> *(2) The distribution services being provided to net-metered customers when the distributed generation is not producing electricity;*
>
> *(3) Simplicity, understandability, and transparency of rates to all customers, including non-net metered and net-metered customers;*
>
> *(4) Equitable ratemaking principles regarding the allocation of the costs of the distribution system;*
>
> *(5) Cost causation principles;*
>
> *(6) The general assembly's legislative purposes in creating the distributed-generation growth program; and*
>
> *(7) Any other factors the commission deems relevant and appropriate in establishing a fair rate structure. The rates shall be designed for each proposed rate class in accordance with industry-standard, cost; allocation principles. The commission may consider any reasonable rate design options, including without limitation, fixed charges, minimum-monthly charges, demand charges, volumetric charges, or any combination thereof, with the purpose of assuring recovery of costs fairly across all rate classes.*

Items 1, 3, 4, 5, and 6, and the opening clause in 7, in this list suggest that in addition to the traditional rules of rate design and "cost causation," the Legislature wants the Commission to think about this rate design in the context of Rhode Island's broader energy policy legislation and goals—including, of course, the 2006 Least Cost Procurement and System Reliability Act and the Renewable Energy Growth legislation in particular.

Q: Should the REG legislation be considered consistent with and supplementary to Rhode Island's 2006 Least Cost Procurement and System Reliability legislation?

A: Yes. I believe it is very consistent with that foundational legislation. The vision laid out in the 2006 Act is impressive. It requires that efficiency, load control, conservation, system reliability planning, and traditional supply planning be integrated into a coherent strategy to meet Rhode Island energy needs. The legislation repeatedly refers to distributed resources and demand management as part of least-cost procurement:

> R.I.G.L.§39-1-27.7 *System reliability and least-cost procurement. – Least-cost procurement shall comprise system reliability and energy efficiency and conservation procurement as provided for in this section and supply procurement as provided for in § 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical and natural gas energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible.*
>
> *(a) The commission shall establish not later than June 1, 2008, standards for system reliability and energy efficiency and conservation procurement, which shall include standards and guidelines for:*
>
> *(1) System reliability procurement, including but not limited to:*
>
> *(i) Procurement of energy supply from diverse sources, including, but not limited to, renewable energy resources as defined in chapter 26 of this title;*
>
> *(ii)* ***Distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems,*** *which is reliable and is cost-effective, with measurable, net system benefits;*
>
> *(iii)* ***Demand response, including, but not limited to, distributed generation, back-up generation and on-demand usage reduction, which shall be designed to facilitate electric customer participation in regional demand response programs, including those administered by the independent service operator of New England ("ISO-NE") and/or are designed to provide local system reliability benefits through load control or using on-site generating capability;***
>
> *(iv) To effectuate the purposes of this division, the commission may establish standards and/or rates (A) for qualifying* ***distributed generation, demand response, and***

> ***renewable energy resources****; (B) for net-metering; (C) for back-up power and/or standby rates that reasonably facilitate the development of distributed generation; and (D) for such other matters as the commission may find necessary or appropriate.*
>
> *(2) Least-cost procurement, which shall include procurement of energy efficiency and energy conservation measures that are prudent and reliable and when such measures are lower cost than acquisition of additional supply,* ***including supply for periods of high demand****.* (Emphasis added)

> R.I.G.L.§39-1-27.8 *Supply procurement portfolio. – Each electric distribution company shall submit a proposed supply procurement plan or plans to the commission not later than March 1, 2009, and each March 1, thereafter through March 1, 2018.* ***The supply procurement plan or plans shall be consistent with the purposes of least-cost procurement and shall, as appropriate, take into account plans and orders with regard to system reliability and energy efficiency and conservation procurement.”*** (Emphasis added)

Based on this content, it is my opinion that the Renewable Energy Growth program is consistent with the spirit and intent of the 2006 legislation and builds on the foundation that this legislation laid. It should be considered in the larger context that legislation creates. It is completely appropriate for the Commission to consider the REG issues in the broad vision and framework laid out in R.I.G.L. §§39-1-27.7 and 39-1-27.8.

That Rhode Island should consider least-cost procurement, system reliability, conservation procurement, demand response, and load control, and even supply procurement as tools in an overall approach to the state’s energy strategy is clear in the above-referenced law.[2]

Both least-cost procurement and system reliability planning explicitly require that the time of energy use and demand be considered as a part of Rhode Island’s approach to providing energy service. Therefore, it is appropriate for the Commission to consider how new distributed energy resources, principally

[2] The EERMC is charged to look not only at least-cost procurement, but also at system reliability planning, generally.

generation (renewable and CHP) and energy efficiency, can be advanced in a manner that creates a more reliable and lower cost energy system.

National Grid's rate design proposal in this context, in my opinion, misses the opportunity to advance the Rhode Island system into a new era of cost-effective reliability and economic health that is potentially available to utility systems throughout the United States.

Q: Is your conclusion that it would be a constructive step to expand the current discussion into a broader consideration of the larger opportunity you have addressed in your testimony and illustrated through your exhibits?

A. Yes, it is.

Q. Is it time for National Grid to invest in a modern, dynamic, customer-partnered distribution system that can fairly track the real costs and benefits customer investments can (or could) provide?

A. It might well be. I have not performed an analysis that could demonstrate its current cost effectiveness. I am, however, concerned that, based on my experience, the discussion of this possible course of action is not being considered with the kind of transparency and directness expected of a system entity that is charged with providing a public service and public benefits. I would emphasize that the issue before us is not simply a potentially significant investment in new advanced metering infrastructure and supervisory control and data acquisition ("SCADA") infrastructure, but the Company's readiness and commitment to use these technologies to effect a new relationship with customers and markets.

Q. Is it time for National Grid (and the parties to this Docket) to address the issues of what demand response and load management effort might (as part of least-cost procurement) provide more benefit to Rhode Island and its people?[3]

A: Yes, it is my opinion that it is. If these issues are fully considered by parties and regulators and the answer is "No," then the proposed rate design might be

[3] Please see the discussion in "The Economics of Demand Flexibility" in Section 3, pp. 29-50, for illustrations of this kind of analysis in a widely varied set of utility settings.

considered as a valid option. But National Grid's explicit assumption in this filing is that this discussion is not on the table now. It is instead prospectively on the table for some undetermined time in the future. The Company makes no suggestion as to how or when that discussion might commence.

It would not be unreasonable, and it might be most appropriate, for the Commission to delay this proceeding in order to explore the underlying issue of what Rhode Island might do now to promote the exciting future that National Grid outlines, but chooses not to advance. The Commission, for example, could deny approval of this filing, finding it a step in the wrong direction.

One important independent analysis that could be undertaken to inform these proceedings more fully would be an assessment of the near-term impact of new REG installations on National Grid's ability to fairly recover distribution system costs. Assume, for a moment, that the impact is small, and an opportunity exists within a reasonable timeframe to design a better system that would fully reflect the goals of the REG Act and the Least Cost Procurement statute (R.I.G.L.§39-1-27.7), and also provide fair and full recovery of actual distribution costs. In that case, the resulting rate design would be consistent with both the spirit and the letter of Rhode Island law.

A constructive "next step" might be to schedule a hearing in which the issue of postponing a decision on this filing, or making a swift negative finding, is discussed directly. This step would allow the Commission to assess the potential benefits and risks of such an action, and to outline constructive steps for moving toward a cost-effective solution that benefits customers and the Company alike. Of course, I would defer to the Public Utilities Commission as to the appropriate strategy for enlarging and advancing the needed discussion.

Q: Does this conclude your testimony?

A: Yes, it does.

SCUDDER H. PARKER

Senior Policy Advisor
Vermont Energy Investment Corporation
128 Lakeside Ave, Suite 401, Burlington Vermont, 05401
802.540.7623
Sparker@veic.org

Scudder Parker is an expert in the development and implementation of energy policy, particularly regarding energy efficiency and renewable energy. As Senior Policy Advisor, he assists in the policy development and communications for VEIC. Parker helps lead the organization toward a total energy approach to implementing its mission. He devises and supports legislation in Vermont that enables Efficiency Vermont to support cost-effective strategic electrification as part of its mandate.

Previously, Scudder has served as VEIC's Policy Director, and Director of the Consulting Division. He provided overall direction to the analysis of energy efficiency and renewable energy markets, programs, and policies; national and international client base growth; staff training and mentoring; and business development for new projects. He made energy policy recommendations for many jurisdictions, analyzed the role efficiency can play in deferring the need for new power plants, improved efficiency operations, and led negotiations with utilities and other stakeholders regarding efficiency goals and program design.

Before coming to VEIC, Scudder was the Director of the Energy Efficiency Division for the State of Vermont's Department of Public Service. Scudder's work shaped the concept of the Vermont efficiency utility. He has led consulting projects focused on the creation of the necessary infrastructure for achieving aggressive efficiency savings and renewable energy targets.

PROFESSIONAL EXPERIENCE

Vermont Energy Investment Corporation, Burlington, VT

2015 – Present
Senior Policy Advisor

2013 – 2015
Policy Director
Work in Vermont and Rhode Island focuses on the creation of new opportunities, specifically related to demand response, the strategic electrification of energy improvement measures that have traditionally relied on fossil fuels or inefficient electric technology (for example, cold-climate heat pumps, heat pump water heaters, electric vehicles), and system integration.

2010 – 2013
Director of Consulting

2007 – 2010
Managing Consultant
Managed complex projects related to achieving aggressive efficiency and renewable energy targets. This included development of energy policy recommendations for several jurisdictions; analysis of the role efficiency can play in deferring the need for new power plants and other supply side investments; development of plans for structuring and launching new and / or improved efficiency operations; leading negotiations with utilities and other stakeholders regarding efficiency goals, budgets, efficiency program designs; integration of efficiency and

renewable energy efforts; and the development and defense of regulatory testimony in both the U.S. and Canada. Projects:

- American Municipal Power. Led a team that is developed a new implementation strategy for energy efficiency service delivery in Ohio. This included the design of a suite of programs for their 120+ municipal utilities, as well as innovative approaches for dealing with the non-contiguous nature of their service territories.
- Ontario Green Energy Coalition. Submitted regulatory testimony in Ontario proposing and defending a very aggressive suite of energy efficiency and distributed resource acquisition strategies as part of Ontario's energy resource planning.
- Iowa Consumer Advocate. Submitted and defended testimony in Iowa stating that a proposed 640 MW coal plant could be avoided or deferred through more aggressive and comprehensive implementation of Energy Efficiency programs.
- Rhode Island Energy Efficiency Resource Management Council. Lead a team of consultants to support implementation of the Council's comprehensive energy efficiency least-cost procurement. This includes leading extensive negotiations with the local utilities on goals, budgets and designs of efficiency and renewable energy programs and strategies.
- New Generation Partners. Assisting VEIC in the development of a new business venture designed to provide support the development of community scale renewable energy and combined heat and power projects.

2007
Independent Consultant, Montpelier, VT
Worked with a coalition to develop legislation that would expand Vermont's Energy Efficiency Utility, Efficiency Vermont, to be a permanent provider of all-fuels efficiency. Helped form and worked with a broad coalition including business, advocacy, utility, low-income groups, and professional associations. Legislation passed; vetoed by Governor.

2005 - 2006
Democratic Candidate for Governor of Vermont, Montpelier, VT
Ran a 16-month campaign for Governor of Vermont. Strong grassroots, issue-oriented and community-based campaign.

2004 - 2005
Public Policy Coordinator, **Vermont Businesses for Social Responsibility (VBSR)**
Worked with VBSR Policy Committee on numerous issues and policy development activities. Worked effectively with new Chair and members (of both political parties) of the House Natural Resources and Energy Committee to secure passage of innovative energy legislation, including expansion of the authority of and funding for Efficiency Vermont. Also worked to pass the SPEED program, an innovative approach to promoting affordable renewable energy development in Vermont.

2003 - 2004
Independent Consultant, Montpelier, VT
Provided energy consulting services to a range of clients. Key clients and projects included:

- Conservation Law Foundation. Filed testimony in Docket No. 6860 on alternatives to construction by VELCO of a high-voltage power lines in Vermont's northwest.
- Vermont Public Interest Research Group (VPIRG). Assisted in preparation of an alternative electric energy supply plan for State of Vermont in 2020.
- Synapse Energy Economics. Co-authored paper on Independent Administrative Systems for delivery of energy efficiency programs.

- Vermont Electric Cooperative. Advised as VEC sought to acquire the larger adjoining service territory of an investor-owned electric utility. Assisted on all matters relating to acquisition terms, conditions and price. Facilitated a process of integration planning between both utilities. Helped write the Integrated Resource Plan (IRP) for both utilities as an integrated and coherent document. Advised the utility on energy efficiency, distributed generation, load control, and purchased power. The IRP was filed on time and the acquisition was approved.

1990 - 2003
***Director, Energy Efficiency Division*, Vermont Department of Public Service**
Appointed by Governor and served as the first Director of the Energy Efficiency Division. Created an entity that became an effective and innovative force to implement a whole new approach to providing energy security and affordability. Built a core staff of 8 people. Selected and managed numerous consultants. Directly responsible for formulating and implementing policy related to Demand Side Management and renewable energy development. Worked closely with Commissioner and other Department Directors in both formal and informal settings in policy development and implementation. Significant activities:

- Co-authored two Vermont Comprehensive Energy Plans, and one edition of the Vermont Twenty Year Electric Plan.
- Built staff capacity to take responsibility for Demand Side Management activities in Department.
- Developed a staff with a strong sense of purpose and commitment to the challenges faced; maintained high level of morale and dedication to innovation and learning new skills.
- Developed concept of a “consumerco,” a consumer cooperative to deliver comprehensive energy and efficiency services for customers.
- Proposed and fully developed the concept of an Energy Efficiency Utility (EEU) to deliver integrated statewide energy efficiency programs. Oversaw all aspects of designing, screening, writing, presenting, and defending this proposal in the report: The Power to Save: A Plan to Transform Vermont’s Energy Efficiency Markets, and in Public Service Board Docket No. 5980. Led the transition process from utility programs to creation of the EEU, including: direct negotiation with utilities and drafting of settlement agreement; legislative effort to change Vermont law to make the EEU possible; writing RFP for EEU selection process; writing performance contract with EEU once selected. After implementation of Efficiency Utility, oversaw design and implementation of a comprehensive evaluation effort involving DPS staff and consultants. Budget for this activity was over $1,000,000 for a 3-year period.
- Played a lead role in development of Distributed Utility Planning Collaborative under Docket 6290, resulting in settlement with numerous Vermont utilities on how to apply principles of Least Cost Planning to distribution and transmission constraints.
- Played major role in supporting development of renewable energy businesses in Vermont, including farm methane, biomass energy, solar energy, wind energy. This work included grant writing and administration, work with Vermont Congressional Delegation in securing “earmark” funds for Vermont projects, and work with Vermont renewable energy businesses and trade association (REV). Also led Department in creating the Biomass Energy Resource Center (BERC), a not-for-profit organization that helps promote implementation of innovative biomass energy projects.
- Developed and secured legislative approval for proposals to use $1.6 million in Oil Overcharge Funds, including innovative programs in energy efficiency, working with Administration, other state agencies, and the legislature.

- Initiated cooperative efforts to promote energy efficiency with other state agencies, including State Buildings (development of a new construction building standard), Education, Labor and Industry, Transportation, and work with ANR on Air Quality and Act 250 issues.
- Represented DPS and the Administration in successful legislative efforts including: passage of "least cost planning" legislation (1992), development and passage of Residential Building Efficiency Standards (1997), comprehensive electric utility restructuring legislation (passed by Vermont Senate, 1997), and passage of "net metering" legislation" (1998). Prepared and presented legislative testimony, negotiated with parties, helped draft and revise legislation.
- Filed, presented and defended expert testimony in numerous Dockets before the Vermont Public Service Board and in other venues.

1981 - 1988
Vermont State Senator, **Caledonia County** (4 terms)
Served on Senate Finance Committee, 1983-88 (chair from 1985-88). Dealt with all utility-related legislation, as well as tax policy, insurance, telecommunications, industrial development, and municipal and state bonding issues. Served on Senate Natural Resources and Energy Committee, 1981-88. Directly involved in all major environmental, energy and wildlife legislation during that time, including pollution prevention, Act 250, Solid Waste bill, and State Land Use Planning bill.

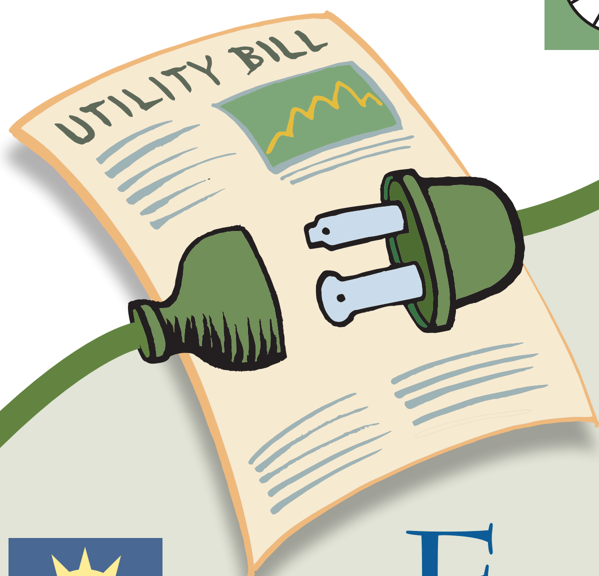
EDUCATION

M.Div. (*cum Laude)*, Union Theological Seminary, 1965-1968.
B.A. (*magna cum Laude*) Williams College, English Literature. Phi Beta Kappa. 1961-1965.

Exhibit No. EERMC - SP-2

RAP® Energy solutions for a changing world

Smart Rate Design



For a Smart Future

Authors

Jim Lazar and Wilson Gonzalez

July 2015

Docket 4568 000033-EERMC

Acknowledgments

This document was authored by RAP Senior Advisor Jim Lazar and Wilson Gonzalez of Tree House Energy and Economic Consulting, with input from RAP Principal Janine Migden-Ostrander, who acted as project lead. The report was produced with support from the Heising-Simons Foundation. During the first phase of this project, RAP conducted a series of interviews over several months with state commissioners, utility and tech-provider representatives, consumer advocates, and other experts to help frame our understanding of and approach to current rate design issues. Several of the people interviewed also provided useful peer review comments on the draft report. Internal review and project guidance was provided by Richard Sedano, Rick Weston, Donna Brutkoski, Brenda Hausauer, Camille Kadoch, and Becky Wigg.

How to Cite This Paper

Lazar, J. and Gonzalez, W. (2015). *Smart Rate Design for a Smart Future.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7680

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July 2015

Smart Rate Design for a Smart Future

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Acronyms

AMI	Advanced metering infrastructure
CP	Coincident peak
CPP	Critical peak pricing
CRES	Competitive retail electric service
DER	Distributed energy resources
DG	Distributed generation
DR	Demand response
EV	Electric vehicle
FIT	Feed-in tariff
IDGP	Integrated distribution grid planning
IRP	Integrated resource planning
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LMP	Locational marginal pricing
MDMS	Meter data management system
NCP	Non-coincident peak
NEISO	New England Independent System Operator
NEM	Net energy metering
O&M	Operations and maintenance
PBR	Performance-based regulation
PTR	Peak-time rebate
PURPA	Public Utilities Regulatory Policies Act
PV	Photovoltaic
REC	Renewable energy certificate
RPS	Renewable portfolio standards
RTP	Real-time pricing
SCADA	Supervisory control and data acquisition
SFV	Straight fixed/variable
SMUD	Sacramento Municipal Utility District
SSO	Standard service offer
T&D	Transmission and distribution
TOU	Time-of-use
VAR	Volt-ampere reactive
VOST	Value of solar tariff

Executive Summary

Introduction

For most of its history, the electric utility industry saw little change in the economic and physical operating characteristics of the electric system. Though the system provided reliable and low-cost service, little in terms of system status or customer use was known in real or near real time. For an industry in the information age, parts of the electric system can be considered rather "unenlightened."

Current advancements in technology will have marked impact on current and future rate designs. First, end-users (i.e., customers) are installing their own generation, mostly in the form of photovoltaic (PV) systems, and are connecting different types of end-use appliances with increasing "intelligence" built in; electric vehicles (EVs), too, are poised to grow rapidly as a whole new class of end-use, just as storage systems are poised to become economic. Second, utilities are deploying advanced metering and associated data systems, sometimes referred to as advanced metering infrastructure (AMI) or smart meters, and more sophisticated supervisory control and data acquisition (SCADA) systems to monitor system operations. To realize the full potential of these new systems and end-uses, regulators, utilities, third-party service providers, and customers will need to utilize more advanced rate designs than they have in the past.

Rate design is the regulatory term used to describe the pricing structure reflected in customer bills and used by electric utilities in the United States. Rate design is not only the itemized prices set forth in tariffs; it is also the underlying theory and process used to derive those prices. Rate design is important because the *structure* of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers, utilities, and other electric market participants. The structure of rate designs and the prices set by these designs can either encourage or discourage usage at certain times of the day, for example, which in turn affects resource development and utilization choices. It can also affect the amount of electricity customers consume and their attention to conservation. These choices then have indirect consequences in terms of total costs and benefits to society, environmental and health impacts, and the overall economy.[1]

Rate design is important because the *structure* of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers, utilities, and other electric market participants.

Despite its critical importance, rate design is poorly understood by the general public and often lacks transparency. The difference between a progressive and regressive design can have a large effect — 15 percent by one estimate, but it could be more — on customer usage.[2] Traditional rate designs, which charge a single rate per unit of consumption (or worse, lower that rate as consumption increases) may not serve consumers or society best. As advancements in technology and customer preferences evolve, the industry must adapt to change or risk the fate of landline telephone companies, which have lost 60 percent of their access lines since the advent of telecommunications competition.[3]

Rate design relies in strong measure upon the judicious application of certain economic guidelines. The following

1 Weston, F. (2000). *Charging for Distribution Utility Services: Issues in Rate Design.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/412

2 Lazar, J. (2013). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6516. Appendix A provides a calculation of how rate design can influence consumption.

3 Federal Communications Commission (2014, October). *Local Telephone Competition Report*, available at: https://www.fcc.gov/encyclopedia/local-telephone-competition-reports

elements of economically efficient rate design that are necessary to address current and coming challenges in the electric industry are based on those laid out in James Bonbright's 1961 *Principles of Public Utility Rates,* and in Garfield and Lovejoy's 1964 *Public Utility Economics.* These principles require that rates should:

- Be forward-looking and reflect long-run marginal costs;
- Focus on the usage components of service, which are the most cost- and price-sensitive;
- Be simple and understandable;
- Recover system costs in proportion to how much electricity consumers use, and when they use it;
- Give consumers appropriate information and the opportunity to respond by adjusting usage; and
- Where possible, be temporally and geographically dynamic.[4]

Rates can be designed to meet (or, in the case of poor rate design, frustrate) public policy objectives to use electricity more efficiently, meet environmental goals, and minimize adverse social impacts, including public health, among others. They are also pivotal in providing utilities the opportunity to recover their authorized revenue requirement. Revenue adequacy is a core objective of rate design, but the more constructive design ideal for rates is forward-looking, so that future investment decisions by the utility and by customers can be harmonized.

Based on these historical works, and looking forward to a world with high levels of energy efficiency, distributed generation (DG), and customer options for onsite backup supply, the following three fundamental principles should be considered for modern rate design:

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

Principles for Modern Rate Design

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

These principles and priorities should be reflected in smarter rates designed to maximize the value of technology innovations, open up new markets, and accommodate the distribution and diversification of customer-sited generation resources. This necessarily includes consideration of what those future technologies and policies could look like, with a focus on metering and billing, market structure, and pricing. In particular, rate design should provide a "price signal" to customers, utilities, and other market participants to inform their consumption and investment decisions regarding energy efficiency, demand response (DR), and DG, collectively referred to as distributed energy resources (DER). **Bidirectional, time-sensitive prices that more accurately reflect costs most closely align with the principles of modern rate design.**

Challenges in Utility Rate Design

Over the last two decades, federal, state, and local policymakers have implemented policies that have spurred the development of customer-sited DG, in particular customer-sited PV systems. The policies range from federal tax credits to state renewable portfolio standards, Net energy metering (NEM), and interconnection standards.[5]

As the costs of renewable and other DG technologies — wind turbines, small hydro, biomass, and others — have decreased, the options available to customers to procure these technologies have increased. In addition, DG systems are decentralized, modular, and more flexible technologies that are located close to the load they serve. Customers can typically purchase or lease the DG from a third party, often

4 Lazar, 2013, p. 10.

5 Steward, D., & Doris, E. (2014, November). *The Effect of State Policy Suites on the Development of Solar Markets.* NREL. See also the Energy Department's SunShot Initiative, which is a national effort to make solar energy cost-competitive with traditional energy sources by the end of the decade. Through SunShot, the Energy Department supports private companies, universities, and national laboratories working to drive down the cost of solar electricity to $0.06 per kilowatt-hour. Learn more at: http://www.energy.gov/sunshot.

with seller or third-party financing. The increasing amounts of DG are impacting the delivery method of energy, and in the future may gradually shift from an exclusively centralized source of power, such as coal, nuclear, or natural gas-fired plants, to a mix of centralized and decentralized, smaller, and customer-centric sources of energy. Rate design must efficiently and fairly incorporate DG contributions to the grid, as well as fairly allocate the benefits and costs of their use for DG customers, non-DG customers, and for the grid.

At low levels of installation of distributed renewables (e.g., under five percent of customers), few if any physical modifications are required to electric distribution systems.[6] The scenario changes once solar output exceeds total load on a given substation. This is being experienced in Hawaii, which has the highest PV penetration of any state and where more than ten percent of residential consumers have PV systems installed. Installation rates are more than twenty percent in many single-family residential neighborhoods. At this level of solar saturation, changes to distribution systems may be needed. Hawaii is serving as a laboratory as it adapts to a high-renewable environment, and this paper explores the various adaptations that this state and many other jurisdictions are exploring and implementing.

In addition to increasing penetrations of distributed renewables, other technologies that will increase in the near future will need to be considered by utilities and regulators as they navigate the changing electric system landscape. EVs are a small part of the electricity load currently, but growth in the sector is likely for many reasons — lower battery costs and emissions regulations that are pressuring the industry to find zero-emissions transportation solutions.[7] Because of the presence of batteries in the vehicles and the ability to control the timing of when they are charged, EV loads can be very different from traditional loads. Encouraging behavior that optimizes EVs' use of the grid requires that rates be designed to provide an incentive for EV owners to charge their cars at the right time. This requires time-sensitive pricing, a topic this paper explores in detail.

Interfacing with **microgrids** will be another near-future challenge for utilities. These may range from an individual apartment building or office complex with onsite generation to a municipal electric utility connected to an adjacent larger utility. These will depend on utilities for some service, and compensation to utilities is important; however, microgrids will also provide services to utilities at times, so the compensation framework needs to be bidirectional.

Storage technologies such as Tesla's new Powerwall battery could be a game changer if they can be distributed in communities, interconnected with a smart grid, and not be price-prohibitive.[8] Currently, energy supply (generation) and loads (end-uses) must be instantaneously kept in balance, even as customers change their end-uses. But the presence of significant storage on the system would allow generators to generate when they can, while allowing the storage technology to provide additional energy or absorb additional energy as loads change.

The presence of generation, storage, and smart control technologies at customer premises offers the opportunity for customers to provide a number of valuable functions to the grid. These generally fall into a category termed **"ancillary services"** and include voltage regulation, power factor control, frequency control, and spinning reserves.[9] Where system operators or third-party aggregators have the ability to control end-use loads, customer appliances can deliver DR during high cost periods or when the grid is at or near its operating capacity and may be at risk for system failures. Rate design can either enable these values to be garnered or erect barriers to them.

6 Hawaiian Electric Company, with 11-percent PV saturation, is just now beginning to invest in distribution system modifications to adapt to high levels of solar energy. See: Hawaiian Electric Company Distributed Generation Interconnection Plan. (2014).

7 MJ Bradley & Associates. (2013). *Electric Vehicle Grid Integration in the US, Europe, and China.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6645

8 "Storage" involves a series of acts: converting grid-interconnected electricity to another form of energy, holding that other form of energy for future use, and then either using it in the form stored (thermal or mechanical energy) or converting it back to grid-interconnected electricity at a different time. The individual acts that comprise this series may be referenced as, respectively, "charging," "holding," and "discharging." Pomper, D. (2011, June). *Electric Storage: Technologies and Regulation.* NRRI, p 3. To this should be added other forms of energy storage, such as water heater controls, water system reservoir management, and air conditioning thermal storage, which may provide lower cost means to shape loads to resources and resources to loads.

9 Spinning reserves refer to the availability of additional generating resources that can be called upon within a very short period of time. Different utilities and different utility markets use varying response time frames to define spinning reserve services, ranging from instantaneous to up to an hour or so.

Rate Design in Theory and Practice

Balancing Stakeholder Interests

A variety of stakeholder interests are at play in the debate over rate design, and finding common ground is not easy. Regulators face the task of fairly balancing concerns among utilities, consumers and their advocates, industry interests, unregulated power plant owners, and societal interests. The regulator accepting the charge of "regulating in the public interest" considers all of these values.

Reaffirming the Principles of Rate Design in the Wake of Change

Good rate design should work in concert with the industry's clean technologic innovations and institutional changes. Accomplishing this requires the application of well-established principles to inform the design of rates that promote economic efficiency and equity.[10] This will be critical in a future characterized by significant customer-side resource investment and smart technology deployment. The advantages for a state that embraces these efficiency and equity goals are significant, especially in maintaining a state's competitiveness and promoting customer choice and ingenuity.

Best practice rate design solutions should balance the goals of:

- Assuring recovery of utility prudently incurred costs;
- Maintaining grid reliability;
- Assuring fairness to all customer classes and sub-classes;
- Assisting the transition of the industry to a clean-energy future;
- Setting economically efficient prices that are forward-looking and lead to the optimum allocation of utility and customer resources;
- Maximizing the value and effectiveness of new technologies as they become available and are deployed on, or alongside, the electric system; and
- Preventing anticompetitive or anti-innovation market structures or behavior.

Many rate design alternatives have been suggested; most recent studies emphasize the need for time-varying pricing and for some form of DR pricing.[11] At the same time, stakeholders currently face a legacy system of non-time-of-use (TOU) rates that are either flat across all usage levels or are designed with increasing or decreasing prices for increasing amounts of consumption ("inclining block" and "declining block" rates, respectively). They may also include demand charges in addition to energy charges, although various types of TOU rates have been used.

Evaluating and Allocating Costs

The design of rates begins with a functional evaluation of the costs incurred by the utility to provide service to its customers — customer costs, distribution costs, and power supply and transmission costs. A critical step is the allocation of costs among different customer classes — residential, commercial, industrial, and others.[12] These allocations, typically based on both marginal and embedded cost studies, inform regulatory determinations of revenue responsibilities among the customer classes.

Once the customer class revenue burdens are determined, prices must be set to generate those revenues, in light of expectations of demand for electricity. The general principle that the cost-causer should pay prices that cover the costs he or she causes might also suggest that the nature of the causation and the form of the price are critically related. And, indeed, price elements have traditionally been fashioned to reflect the nature of the cost to be recovered: costs that vary directly with energy usage are recovered in energy (kilowatt-hour [kWh]) charges, costs that are driven by peak demands (whether at the generation, transmission, or distribution level) are recovered in or time-varying kWh charges, and customer-specific costs unrelated to usage are recovered in customer charges. Of course, rate designs vary greatly across customer classes and utilities generally — demand charges,

10 These principles, on the basis of which James Bonbright and Alfred Kahn, among others, framed their analyses of regulation and the public good, are long embedded in regulatory law and practice throughout the United States. See, by way of example, the National Association of Regulatory Utility Commissioners' *Resolution Adopting 'Principles to Guide the Restructuring of the Electric Industry'*, adopted July 25, 1996, NARUC Bulletin No. 32-1996, p 10.

11 See the bibliography for references to a number of current publications on rate design.

12 For a discussion of how costs are typically assigned to different rate classes, see: Lazar, J. (2011). *Electricity Regulation in the US: A Guide.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/645, Section 9.4.

for instance, are rarely imposed on low-usage customer classes — but the basic architecture is well established and ubiquitous. It has been possible only because the industry in question is a monopoly.

The logic of differentiated pricing based on the differing natures of the underlying costs — specifically, their energy, capacity, or customer-specific characteristics — can be taken only so far. All industries are characterized by some combination of variable and fixed (in the short run) costs. In competitive markets, those costs are covered (or not) by the sale of goods and services; and the prices of those goods and services represent the value of society's resources that are being put to their production — or which are saved if those goods and services are not demanded. Economic efficiency — the greatest good for the lowest total cost in the long term — is served in this way. Monopoly services, simply because they are provided by monopolies, are not entitled to pricing structures that are not sustainable in competitive markets — that is, that are adverse to economic efficiency in the long run (within the constraints of other public policy objectives).

Basic Rate Designs

The simplest form of rate design is the **flat rate**, which is derived by simply dividing the revenue requirement for a given class of customers by the kilowatt-hour sales, and charging a purely volumetric price. A very important principle of rate design is to align the incremental price for incremental consumption with long-run incremental costs, including societal costs. Use of short-run costs, dispatch modeling, or a non-renewable resource as the basis for "incremental cost" is inappropriate and misleading to the consumer and society because it fails to recognize the real costs associated with plant investment and resource choices, many of which have long-term consequences on the order of half a century or more.

Customer charges are per-month fixed charges that apply to each customer in a tariff class, regardless of their usage. This paper addresses these in great detail, to focus attention on those charges that actually change with the number of customers. Although some utilities and regulators use customer charges to recover distribution system costs, this paper demonstrates that this is neither cost-based nor economically efficient. High customer charges impose unfair costs on small-use residential consumers, including most low-income household and apartment residents. The fixed charge for residential or commercial service should not exceed the customer-specific costs attributable to an incremental consumer.

Demand charges are commonly used to recover some costs of generation, transmission, and distribution of large commercial and industrial customers. Because traditional demand charges are measured on the basis of the individual customer's peak, regardless of whether it coincides with the peaks on any portion of the system, this approach inevitably results in a mismatch between the costs incurred to serve the customer and the prices charged if the customer's peak is non-coincident with the system peak. This means a customer is charged the same rate whether they use power in times of high demand (adding to system peak and utility costs) or low demand (when utility costs are correspondingly lower). Demand charges were implemented for commercial and industrial customers in an era during which sophisticated metering was prohibitively expensive. Today, with smart meters and AMI, these metering costs are trivial. Movement away from demand charges, toward more granular time-varying energy rates, is appropriate.

A few rate analysts have recommended that demand charges be extended from large commercial customers (where these are nearly universal) to small commercial and residential consumers.[13] Some of these analysts suggest this is an appropriate way to ensure that solar customers contribute adequately to system capacity costs. This option is inapt for most situations for several reasons. The only distribution system component sized to individual customer demands is the final line transformer. The relatively small portion of cost of service represented by the line transformer required to serve solar customers amounts to only about $1/kW/month. In addition, the diversity of customer demand at any given time of the day, and the lack of understanding of the potentially complex concept, suggest against this option. **Time-differentiated prices** can more equitably recover costs that are actually peak-oriented from all customers, including solar customers. However, customer education is a crucial part of this transition.

Energy charges are per-kWh charges for electricity consumed. These can be arranged into inclining or declining block rates, into seasonal charges, and into time-varying charges. This paper finds that time-varying (and, eventually, as technology enables customers to respond, more dynamic) energy charges are the best way to reflect costs to consumers and to encourage efficient use of electricity.

13 See, e.g.: Hledik, R. (2014). Rediscovering Residential Demand Charges. *Electricity Journal,* 27(7), August–September 2014, pp. 82–96.

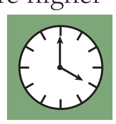
Table ES-1

Illustrative Residential Rate Design		
Rate Element	**Based On the Cost Of**	**Illustrative Rate**
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + Transmission and Distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

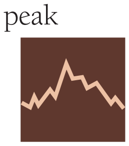
Time-Varying Rates

It is hard to envision an electric system future without greater use of time-differentiated pricing. Because the underlying costs of providing electricity vary hourly and seasonally, it is impossible for the customer to see to an appropriate price signal without that signal also varying over time. As smart technologies take hold, the connection between customer usage patterns and underlying costs will become apparent. As this happens, it is inevitable that time-differentiated pricing will become more widespread.

TOU rates have been in use for some time in the United States. These rates typically define a multihour time of the day as an "on-peak" period, during which prices are higher than during "off-peak" hours. In most cases, on-peak periods are limited to weekdays. TOU rates are an improvement over flat or inclining block rates because they offer some correlation between the temporally changing costs of providing energy and the customer's actual consumption of energy. However, they are usually not dynamic in the sense of capturing the real underlying changes of costs from hour to hour, day to day, or season to season. Concentrating peak-related charges into as few hours as possible produces a better customer response.



Critical peak pricing (CPP) and peak-time rebate (PTR) are a variation on the TOU concept. Under CPP, prices during a limited number of specific "critical peak periods" are set at much higher prices. The customer is given some advance notice of critical peak days, usually a day in advance. CPP is designed to produce a response — to get customers to reduce loads during critical peak periods. The CPP has been largely successful. To date, CPP rates have been voluntary opt-in rate forms, but evidence supports setting these as default rates for large groups of consumers. Under the PTR concept, rather than charging customers a high critical peak price, customers are given a large credit on their bills if they can reduce usage during a peak-time event. PTR is distinguishable from a CPP in that it is a voluntary program. Just as in the case of TOU, both CPP and PTR require the use of an interval meter or a smart meter.

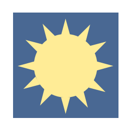


Real-time pricing (RTP) charges the customer the actual prices being set in wholesale markets (for utilities that are not vertically integrated) or short-run marginal generation costs (for vertically integrated utilities) as they vary hour by hour. Prior to the introduction of smart technologies, only the largest customers would typically be on real-time rates. As newer smart technologies take hold, some form of RTP may expand to other customers who have smart appliances that can monitor prices automatically, respond accordingly, and monetize the benefits.

Rates to Compensate DG

Several jurisdictions have adopted special pricing for compensation of solar customers for the power supplied to the grid by these systems.

Originating in Europe, **feed-in tariffs** (FIT) pay a premium price for renewable energy, generally based on the cost of the resources, not the value of the output. The payments for solar were typically higher than for wind, and the payment for power from small systems was greater than for larger systems. FITs were generally designed to be an infant-industry incentive.



A **value of solar tariff** (VOST) is fundamentally different from a FIT, compensating the solar provider on the basis of the value provided, not the cost incurred. As studied by Austin, Texas, plus the states of Minnesota and

Maine, a VOST will generally provide equal or greater compensation to the solar producer than simple NEM, reflecting the combined high value of the energy and non-energy benefits provided by solar.

Net energy metering (NEM) is an approach that measures the customer's net usage from the grid, and charges that usage at the standard tariff price for electricity. In effect, NEM allows customers to exchange excess generation from their solar (or other onsite) generators at times they do not need it for power from generic grid resources (usually fossil fuels) at other times.

For utilities in which only a small percentage of consumers have installed solar systems, a simple NEM option will generally be easier to measure, more acceptable to consumers, simpler to administer, and will produce fewer significant impacts on grid-dependent customers. Another option is **bidirectional pricing**, especially where solar penetration is high. Bidirectional pricing, which would require a smart meter, would allow the customer to pay the retail rate for any power consumed and be compensated based on the full value of the energy delivered to the grid. Time-differentiated pricing for power flows in each direction may likewise be appropriate. The customer pays for power used on a TOU basis, and is credited (either the retail TOU rate or a different time-differentiated VOST) for power fed to the utility.

The three principles of modern rate design outlined earlier suggest some other considerations for solar customers:

- Only customer-specific costs should be applied to the bill for the privilege of connecting to the grid and accessing grid services.
- The cost for use of the distribution grid should be charged in relation to customer purchases of energy.
- Time-varying rates are appropriate in both directions of the transaction in which a customer is consuming and selling energy to the grid.
- Some skeptics have portrayed PV as unfairly shifting costs to other customers or of using the distribution system in some way without paying for it. This is a misapplication of rate design and cost recovery principles and practice which have never charged generators for use of the distribution system, as well as accepted cost allocation methods, which are themselves dynamic in nature.
- DG customers should be free from discrimination. Any cost imposed on a DG customer should be based on a real cost to the utility system resulting from the DG, or net of cost savings resulting from the DG. In the absence of a VOST or other data, NEM is appropriate as a proxy where PV saturation is relatively low. It is unlikely that this will overcompensate DG customers, and likely that it will still send sufficient price signals to the customer to make economic choices about whether to install DG. Where PV saturation is low, the impact on the utility system and revenues would also be quite low.

The success of DG has, unfortunately, prompted the proposal and implementation of rate designs in some states that harm existing DG customers and present a formidable barrier for customers contemplating investments in DG resources.[14]

Rate Designs That Discourage DG

A **minimum bill** charges the customer a minimum fixed charge, which entitles the customer to a minimum amount of energy. For example, a residential minimum bill might charge $20 as a minimum charge, which entitles the customer to receive their first 100 kWh energy included in the price. A flat or inclining block rate structure would then be applied for additional usage. Minimum bills are not typically considered good rate design; they have the effect of reducing the value of energy efficiency, conservation, and customer-sited DG, to the extent those efforts would otherwise reduce consumption below the minimum threshold. The key is to set the minimum bill at a level that guarantees the utility a certain level of revenue it can count on, while not penalizing the vast majority of customers.[15]

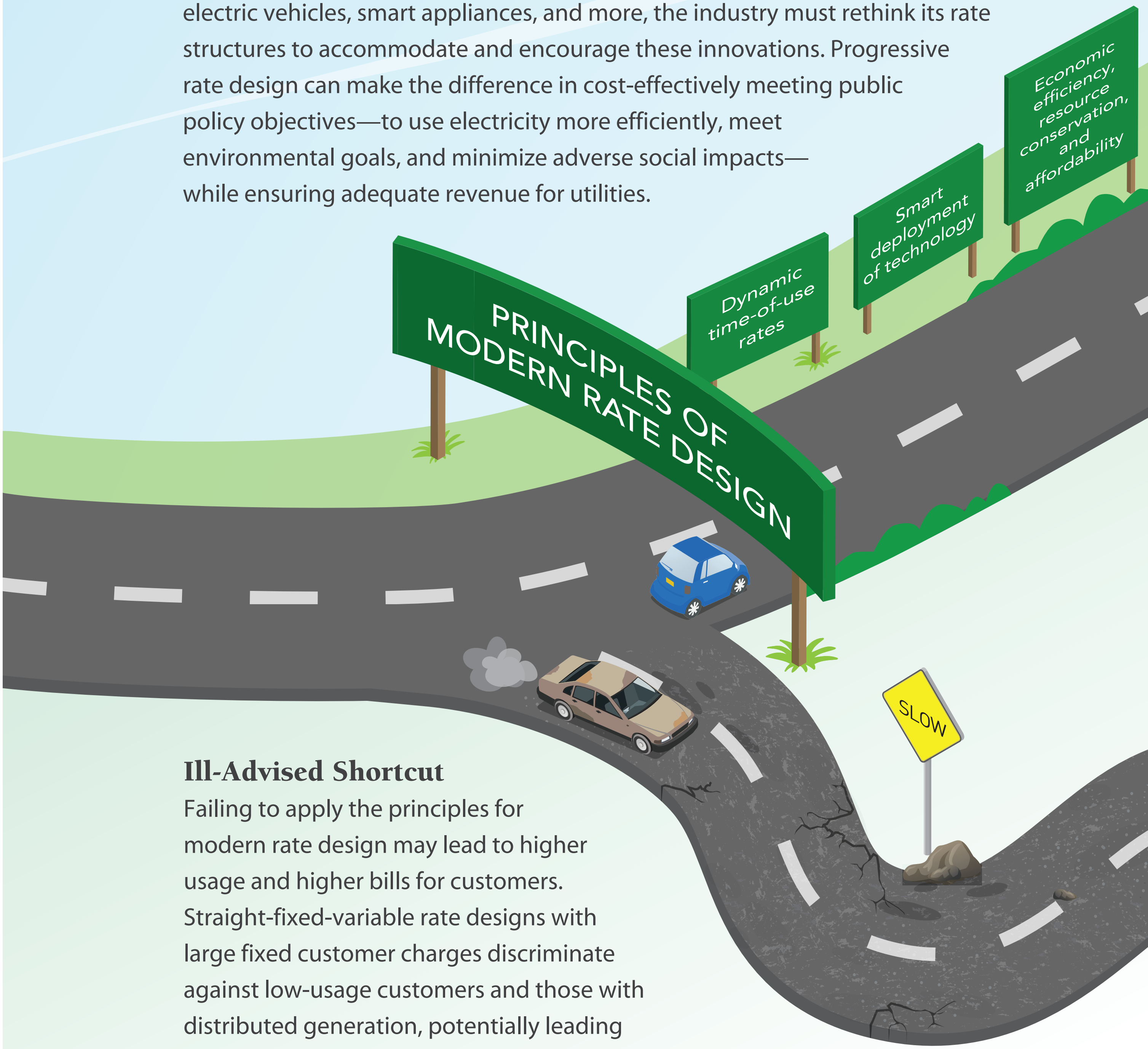
Even less desirable is **straight fixed/variable** (SFV) design. Utilities in some parts of the United States are seeking to sharply increase monthly fixed charges, with offsetting reductions to the per-unit price for electricity. This approach deviates from long-established rate design principles holding that only customer-specific costs — those that actually change with the number of customers served — properly belong in fixed monthly fees. It also deviates from accepted economic theory of pricing on

14 Tong, J., & Wellinghoff, J. (2015, February 13). Why Fixed Charges Are a False Fix to the Utility Industry's Solar Challenges. *Utility Dive.*

15 Lazar, J. (2014, November). *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7361

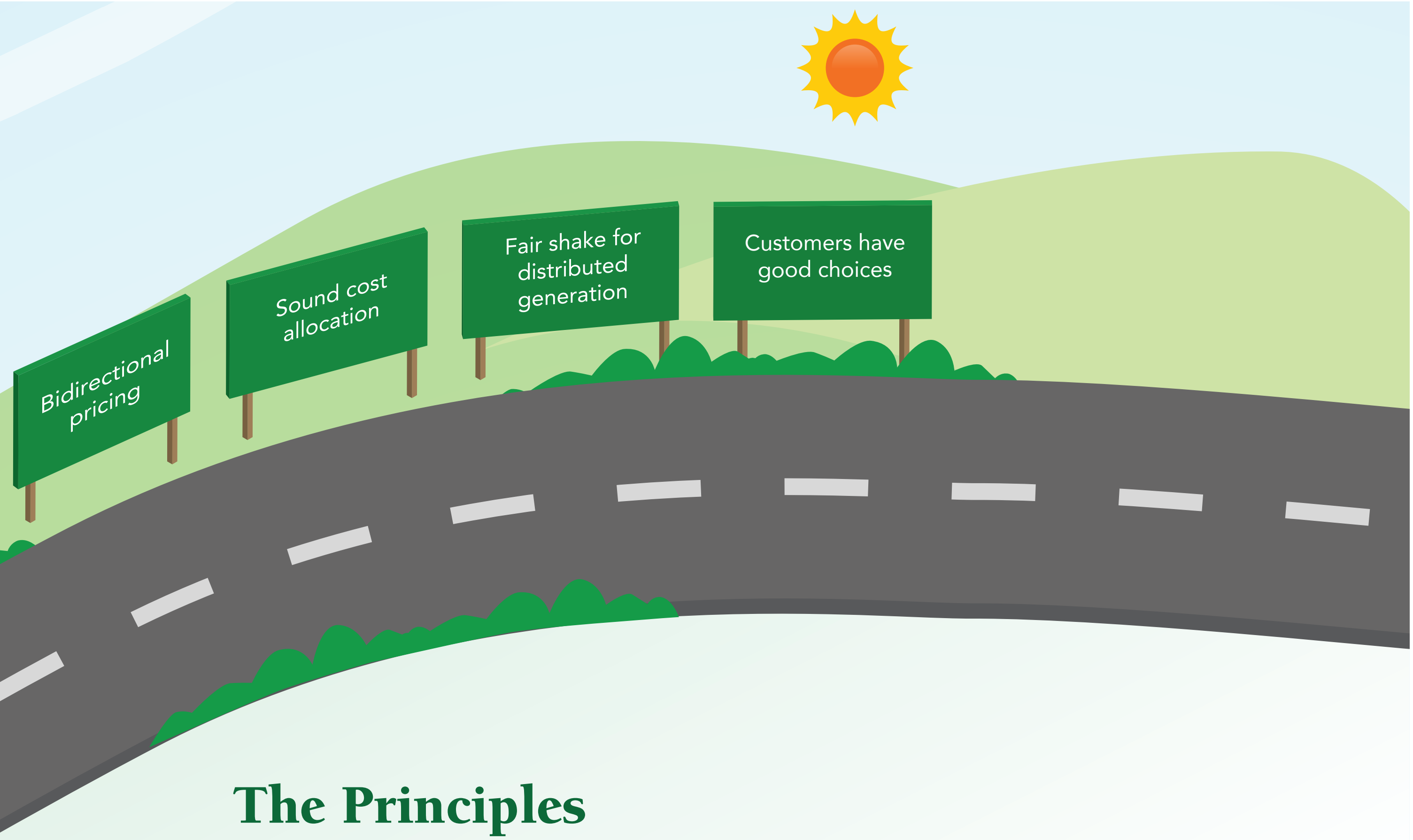
Rate Design Roadmap for the 21st Century Utility

Utilities face unprecedented changes in the way power is generated and delivered. With the ramp-up in distributed generation, energy efficiency and demand response, electric vehicles, smart appliances, and more, the industry must rethink its rate structures to accommodate and encourage these innovations. Progressive rate design can make the difference in cost-effectively meeting public policy objectives—to use electricity more efficiently, meet environmental goals, and minimize adverse social impacts—while ensuring adequate revenue for utilities.



Ill-Advised Shortcut

Failing to apply the principles for modern rate design may lead to higher usage and higher bills for customers. Straight-fixed-variable rate designs with large fixed customer charges discriminate against low-usage customers and those with distributed generation, potentially leading customers to abandon the grid entirely.

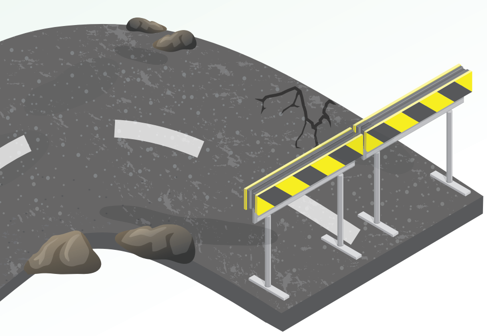


The Principles

1 A customer should be able to connect to the grid for no more than the cost of connecting to the grid.

2 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 Customers that supply power to the grid should be fairly compensated for the full value of the power they supply.



the basis of long-run marginal costs. The effect is to sharply increase bills for most apartment dwellers, urban consumers, highly efficient homes, and customers who have DG systems installed, while benefitting larger homes and suburban and rural customers. Also often impacted are low-income customers who tend to be low-use customers.[16] Large-volume (often wealthier) customers, meanwhile, see decreasing bills.

Some states, such as New Mexico and Arizona,[17] are considering imposing new **distribution system cost surcharges** on DG customers that utilities argue reflect their use of the grid, even though there are no demonstrated additional costs being incurred by the utility as a result of DG output. A Wisconsin utilities commission approved a similar fee for solar users last year.[18]

Exit fees are charges imposed on consumers who cease taking utility service. In general, these are applied only to consumers departing the system on short notice, and for whom the utility has made significant investments to provide service. This may be customer-specific distribution system investments, or may be investments in power supply intended to provide long-term service. As a general rule, exit fees are inappropriate rate design measures. The risk for customer loss is an ordinary business risk, for which the utility rate of return is the compensation.

In contrast to the approaches outlined previously, Figure 1 gives an overview of the appropriate rate designs for all customer classes for both default and optional services.

Figure ES-1

Rate Design Options by Customer Class

	Typical Pre-AMI Rate Design	Inclining Block Rate	TOU Rate Fixed Time Period	TOU plus Critical Peak Pricing	Baseline-Referenced Real Time Pricing	Market Indexed Real Time Pricing
Residential	Flat Energy Charge	Default (if kwh-only metering in place)	Default (if TOU meters or AMI in place)	Optional if AMI in place	Pilot	Not Available
Small Commercial 0-20 kw Demand	Flat Energy Charge	Not Available	Default (if TOU meters in place)	Optional if AMI in place	Pilot	Not Available
Medium General Service 20-250 kw	Demand Charge --- Flat Energy Charge	Not Available	Default (until AMI installed)	Default (after AMI installed)	Optional	Not Available
Large General Service 250-2,000 kw	Demand Charge --- Flat Energy Charge	Not Available	Not Available	Default	Optional	Optional
Extra Large General Service >2000 kw	Demand Charge --- Flat Energy Charge	Not Available	Not Available	Not Available	Customer Must Choose Between These Two Options	

Source: Adapted from RAP research for New England Demand Response Initiative (NEDRI), 2002

16 USEIA. (2014). Extracted by National Consumer Law Center.

17 In February, an Arizona utility voted to impose a monthly surcharge of about $50 for NEM customers (Warrick, 2015).

18 Content, T. (2014, November 14). *Regulators Agree to Increase Fixed Charge on WE Energies Electric Bills.* Milwaukee Journal Sentinel.

Enabling Smart Technology

Utilities from Maine to California have deployed smart grid upgrades or are beginning the transition to a smarter grid.[19] These upgrades promise to deliver an entirely new level of information about system operations and consumer behavior. In short, the information age is coming to the electric industry.[20] Computerizing the traditional grid with AMI and advanced SCADA systems will enable the development of new and dynamic rate offerings. Meanwhile, smart home appliances that can monitor pricing conditions and be made dispatchable by system operators will assist customers in managing their usage. Moreover, these new technologies will aid system operators in minimizing total system costs and increasing system reliability.[21] They will also help accommodate customer-owned generation, utility-scale renewable power, energy storage (both customer- and utility-scale), EVs, and microgrids.

Smart meters provide data acquisition, equipment control, and communication capability between the customer and the power grid.[22] They are able to record customer usage at a fine time scale and then communicate that information back to the utility and to the customer. This information can in turn be used to control end-use appliances in response to price signals and system conditions. When used by system controllers, they can aid in reducing loads during times of system stress. When employed by the customers or on their direct behalf, smart meters can be used to shift usage from on-peak to off-peak periods, utilizing low operating cost renewable energy.

Smart meter deployment is expected to reach 91 percent of the United States by 2022.[23] It is important to note, however, that merely installing smart meters does not alone facilitate advanced pricing. Meter data management system (MDMS) investments, billing engine modifications, and sophisticated rate studies are needed to develop advanced pricing.[24] Although smart meters can enable advanced pricing mechanisms, given the relative price-variability risks and economic rewards of different types of pricing, the desired consumer rewards of lower bills are applicable only to a subset of pricing options, primarily TOU, CPP, and RTP.

Smart meters and the associated MDMS perform multiple functions. The costs associated with smart grid investments should be apportioned so that the costs are shared by all aspects of utility service that benefit. Simply stated, to justify deployment of smart meters and an MDMS there should be an expected net savings to the utility customers over the life of the investments. No single category (energy, capacity, or customer) should be assigned costs that exceed that particular benefit.

Various technology enhancements can improve the effectiveness of more complex rate designs by enabling customers to respond to prices automatically. Some examples include smart thermostats, grid-integrated water heating, EV chargers, and vehicle-to-grid applications.

Customers who have PV systems or other onsite grid-interconnected generation or battery storage systems both take power from the grid and deliver it to the grid. Keeping track of these flows is necessary for accurate billing and crediting of services provided to the grid, when the value of customer production is a priority. Smart meters have this capability and are needed when the rate design requires knowing when power is flowing and in which direction, to more accurately value the cost of customer use and the value of customer production. Clearly if the customer is consuming most of their power during off-peak periods, and supplying power mostly during on-peak periods, the solar customer is providing significant value to the grid that

19 We use the term “smart grid” broadly to include both utility grid-side and customer investments.

20 Determining whether AMI and smart grid are projected to be cost-effective before deployment is an important consideration and one that is beyond the purview of this report. A good discussion on smart grid benefits to costs can be found in: Alvarez, P. (2014). *Smart Grid Hype & Reality.* Wired Group Publishing, ch 4-9.

21 PR Newswire. (2013, January 8). *ComED Launches Smart Home Showcase Contest.* Available at: http://www.prnewswire.com/news-releases/comed-launches-smart-home-showcase-contest-186025412.html

22 They also provide operational benefits like reduced meter reading costs and outage detection.

23 Telefonica. (2014, January). *The Smart Meter Revolution: Towards a Smarter Future.* Available at: https://m2m.telefonica.com/multimedia-resources/the-smart-meter-revolution-towards-a-smarter-future

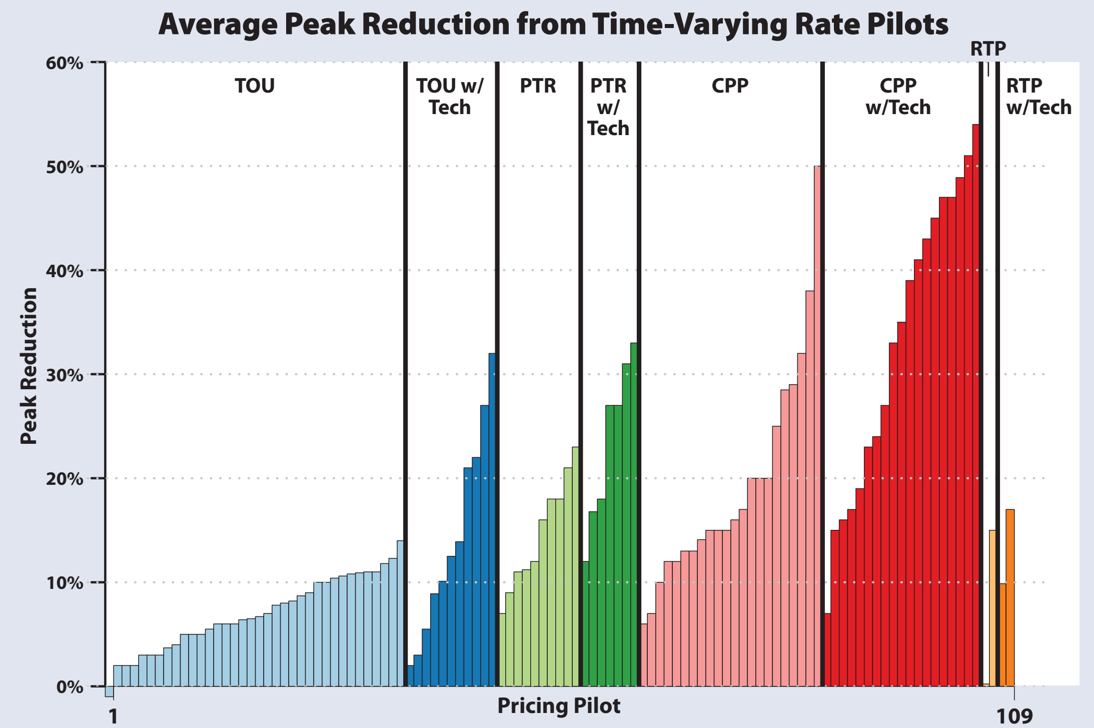
24 Lazar, J. (2013). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6516

is not captured by simple monthly kWh NEM.[25]

The introduction of SCADA systems late in the 20th century enabled grid operators, for the first time, to see how their systems operate at a more granular level and in real or near real time. The addition of smart meters and other devices, collectively referred to as the smart grid, promises to vault the level of sophistication to an even higher level and enable more clearly defined rate designs.

Smart technologies enable distribution optimization in many ways, and rate design will play a key role in bringing customer end-uses into utilities' toolbox of solutions. In addition, it will inform the customer about opportunities to save money and to be rewarded for providing value to the overall grid. Poor rate design can impair this ability and prevent the true value of smart technologies from being realized, clogging the gears of this dynamic.

Figure ES-2



Source: Faruqui, *Time-Varying and Dynamic Pricing,* RAP, 2012

Implementing Smart Rates

"Smart rates" describe those rate designs that require the type of data collection that smart meters provide, and that are expected to produce significant peak load reductions, reduced and shifted energy consumption, improved system reliability, improved power quality, and reduced emissions. These include TOU, PTR, CPP, and RTP (all with and without technology, such as in-home displays).

The effectiveness of different TOU rate designs varies considerably. Figure ES-2 shows a comparison of pilot program peak reduction results for a variety of smart rates. CPP rates clearly show the greatest promise of delivering strong peak reductions by customers.

Currently most utilities that have smart rates offer them as optional services, especially for residential and mass market customers. Some utilities are considering making these rates applicable to all residential consumers, either as the default rate design with the ability for the customer to opt out of the rate, or as a mandatory rate design. Tools to protect customers during this transition may include dual or shadow billing, in which customers still on traditional rates are shown potential savings on their bills; customer guarantees of tariffs that provide them with the lowest bill; "hold harmless" and first-year bill forgiveness programs; and continuation of low-income rates. The critical factor in all of these is that it gives the individual customer the opportunity to compare their bill based on a traditional rate design and a more dynamic rate design.

Evidence shows that advanced pricing works best with technology enhancement to enable automated response to higher prices that can tie directly into time-differentiated prices. Over 200 time-differentiated rate tests have been conducted worldwide, with differing results. The consensus of these pilot programs is that customers respond to prices. Furthermore, enabling technologies (in home displays, smart phone applications, smart thermostats, and

25 "Net energy metering" is a pricing scheme that "pays" for the output of customer-sited generation at the same rate that the customer pays for energy delivered from the electric system.

appliances) enhance price responsiveness. TOU and CPP rates may also be more fair to customers than traditional flat rates, because customers who contribute more to the increased costs of peak usage are made to pay more, while customers who use less of the expensive peak power have the opportunity to save more.[26]

By having rates that reflect system value, customers will have the incentive to take action that over time will reduce system costs, and thus benefit all ratepayers. Overall then, rates should be lower with time-differentiation and critical peak pricing than they would be with traditional rates, owing to reductions in system costs to serve peak demands.

In order for homes to respond to dynamic pricing, either manual customer intervention or automated technology needs to be deployed. Experience shows that automated technology provides greater energy benefits by far. To achieve this, either energy management systems or smart appliances (or both) are required.

The TOU/CPP approach discussed previously is also optimal for customers who own DER. A number of compensation mechanisms have been considered by regulators for distributed resources. They range from value-to-grid approaches using avoided costs to the establishment of a system of distribution credits.[27]

One such incentive is **locational pricing**, which provides incentives for DER that are located in areas that reduce congestion. This can be beneficial to the distribution system, as critically sited DER can lead to the postponement or avoidance of costly upgrades. The pragmatic way to reflect locational values to residential and small commercial consumers is through targeted incentives for peak load management, as are typically provided by energy efficiency suppliers and DR aggregators, not necessarily through complex retail rate designs that consumers may be unlikely to understand.

Separating out the existing cost analysis into its constituent parts — energy, demand, and ancillary services — can also support smarter DR and DER investment. The ancillary services needed in providing electricity service can also promote DER investments that help the grid's reliability and resiliency.

Hawaiian Electric Company has prepared a detailed Distributed Generation Integration Plan, which may be a postcard from the future for mainland utilities preparing for a much higher uptake of solar PV. Key considerations in the overall plan include the correct sizing of line transformers, analysis of when upgrades to circuit capacity are needed, installation of voltage regulators, and additions of electricity storage in some locations. Recovering the costs of **grid modifications** associated with DG is a topic of considerable controversy. In Hawaii, where these modifications are more imminently needed, Hawaiian Electric has implemented a change to require smart inverters, and the overall plan includes installation of voltage regulators, upgrades to substations, upgrades to conductors, and implementation of DR. The determination by the Hawaii Public Utility Commission on the appropriate method for recovery of the associated costs is pending.

Hawaii may be leading the nation in change, but dockets have been convened in Arizona, Colorado, California, New Mexico, and other states examining the appropriate way to recover DG-related grid costs, including modifications needed to adapt to high levels of solar. In general, regulators will weigh issues including the recovery of existing, incremental, stranded, and new generation costs, as well as the role of the value of solar.

The outcome of these investigations will produce different results state by state. In general, states looking ahead at marginal costs will conclude that solar customers are bringing great value to the system, whereas states focused on embedded cost concepts will see stranded cost issues. Adhering to the guidelines below, which follow from the three principles of rate design outlined in this paper, should ensure that solar and other residential consumers are treated equitably.

- **Customer Charges**. Should not exceed the customer-specific costs associated with an additional customer, such as the service drop, billing, and collection.
- **Energy Charges**. Should generally be time-varying and those time differentiations should apply both to power delivered by the utility to customers, and to power delivered to the utility from customer generation. This assures that solar output is valued appropriately, and high-cost periods are reflected in the prices charged to customers using power at those times. Until smart rates are applied universally, it may

26 Traditional flat rates force all customers to a rate based on the average costs assigned to the class, to the detriment of customers who use less on-peak and therefore have less costly consumption patterns.

27 Moskovitz, D. (2001, September). *Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors.* Montpelier, VT: The Regulatory Assistance Project.

be appropriate to make time-varying rates mandatory for solar customers, but optional for small-use non-solar customers (see discussion on this in Chapter VI).

- **Minimum Bills**. Where utilities have high numbers of seasonal customers who only consume power during the summer or winter, an annual minimum bill may be an appropriate rate design to ensure a minimum level of revenue from customers in this category. Otherwise, minimum bills are not a particularly desirable rate design.[28]
- **Demand or Connected Load Charges**. Demand charges are generally inappropriate for residential and small commercial customers who share distribution transformers with other consumers, and where implemented should not exceed the cost of the final transformer, about $1/kW/month. They are never appropriate for upstream distribution costs that can be recovered in a TOU rate. The illustrative rate designs eliminate demand charges entirely except for the final line transformer, including the remaining system capacity costs in TOU and CPP rates.

Optimal rate design choices may also differ according to the level of the utility's costs:

- **Low-Cost Utilities** (average revenue <$0.10/kWh). May need to retain or institute inclining block rates to ensure that the end-block of usage reflects long-run marginal costs for clean power resources, transmission, and distribution.
- **Most (Average-Cost) Utilities** (average revenue $0.10 to $0.20/kWh). Conventional NEM (of the full rate, including volumetric charges for power supply and distribution) is likely an appropriate strategy; although grid operators lose distribution revenues, their consumers gain all of the other benefits of increased renewable generation, and taken as a whole, the value of solar energy added to the system is usually equal or greater in value than the retail electricity price.
- **High-Cost Utilities** (average revenue > $0.20/kWh). Utilities that have average residential prices in excess of the long-run marginal cost of new clean-energy resources ($0.10/kWh to $0.25/kWh) may need to reflect distribution charges separately, collected from all customers receiving grid power, and crediting only a power supply rate when solar power is fed to the grid.

As emerging technologies become more mainstream, rate designs will need to adapt to changes in how customers use electricity and how it impacts the grid. DG can be viewed as a tool to strengthen the grid and rate designs of the future can encourage the utility-customer partnership to ensure the efficiency and economy of the grid. Key will be the temporal rates discussed previously, but innovations in terms of unbundling the customer-generated power to provide ancillary services and providing credits to DER that is strategically located to support the grid will be important components.

This paper also explores other utility strategies to encourage uptake of DER, including green pricing services that allow customers to pay a premium on their bills to support utilities' investment in renewable energy, and design of rates that can compensate customers for ancillary services that they provide the utility, such as the use of smart grid solutions to aid reliability.

Electric Vehicles

EVs are another emerging technology poised to play a growing role in this future, and utilities can use rate design to send EV owners the optimal price signals. Even without AMI deployment, interval TOU meters to be read manually can allow EVs to be separately metered. But a utility that has AMI has many options for providing a rate for EV owners that is appealing to the customer and remunerative to the utility. These can include a simple TOU rate, a multi-period TOU rate with a super-off-peak period, a critical peak pricing rate, or a real-time price.

For public charging stations, a wide variety of pricing schemes are used, from free charging to hourly parking to TOU rates. In states that subject EV charging stations to regulation for the resale of electricity, charging stations avoid regulation by charging for the parking space, often on a time-varying basis, and not charging for the electricity.

One of the great promises of EVs is that they will become fully grid-integrated, providing a market for off-peak power, a source for on-peak power, and multiple ancillary services.[29] This requires a combination of sophisticated

28 Lazar, J. (2014, November). *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7361

29 Lazar, J., Joyce, J., and Baldwin, X. (2008). *Plug-In Vehicles, Wind Power, and the Smart Grid.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Lazar_PHEV-WindAndSmartGrid_2007_12_31.pdf

charging units in vehicles, complex pricing, and a very smart grid. **Vehicle-to-grid** pilot programs that make use of these features are in the early stages.

Policies to Complement Smart Rate Design

Utilities find themselves at a crossroads in which they could embrace or shun rate designs that support a smarter future. The smart future will see extensive use of technology to help consumers manage their energy costs, and utility pricing that enables these savings to occur. A mix of central generation, DG, energy efficiency, DR, and customer response to time-varying pricing will provide a rich mix of reliable and environmentally friendly sources to provide quality service at reasonable costs. Consumers will increasingly have smart homes and appliances, and utilities will use AMI to collect key data from these resources and respond accordingly.

To achieve this smart future, regulators at various levels will have to take many discrete actions, including:

- Utility regulators will need to adopt time-varying and dynamic rate designs, with consumer education, shadow-billing during a pre-deployment phase, a "hold harmless" provision for the first year of implementation, and excellent customer support throughout.
- Some form of revenue regulation will be necessary to ensure that utilities retain a reasonable opportunity to earn a fair return on investment on used and useful property serving the public, and maintain access to capital at reasonable prices.
- State building energy codes will need to require home energy management systems in new homes (as most already do for commercial buildings).
- Customer-sited generation will include: smart inverters, which will provide reliability and ancillary services; customer-sited batteries which will provide service not only to the locations where they are installed, but be available to grid operators for system support; and variable solar orientation to optimize peak time production.
- Federal appliance standards must require installation of control technologies in new major appliances such as refrigerators, water heaters, furnaces, heat pumps, and air conditioners, dishwashers, clothes washers, and clothes dryers, so that they can automatically adjust to changing prices.

High recurring fixed charges provide utilities with stable revenues and address their immediate concerns. In doing so, they punish lower-usage customers, discourage efficiency improvements and adoption of distributed renewables, and over time can lead to an unnecessary increase in consumption or promote customer grid defection.

The "not-so-smart" future would involve movement toward high recurring fixed charges. They provide utilities with stable revenues and address their immediate concerns. In doing so, they punish lower-usage customers and discourage efficiency improvements and adoption of distributed renewables, and over time can lead to an unnecessary increase in consumption or, in the event distributed storage technologies become more accessible, promote customer grid defection. This is to say, such rates are economically inefficient and inequitable and are not justified by any fundamental principle of neoclassical economic theory. They are, in fact, nothing more than a government-sanctioned exercise of monopoly power. The adverse impacts on electric consumers and public policy goals for electricity regulation include skewed incentives against energy efficiency, customers looking to go totally off the grid, and higher bills for most low-income households.

The first of the principles of electricity pricing set out earlier in this paper notes that a customer should be able to connect to the grid for no more than the cost of adding that customer. The imposition of a fixed charge solely for the privilege of being a customer is not common in other economic sectors, from supermarkets to hotels and airlines, that have similarly significant fixed costs to those of utilities. Allowing utilities to impose high fixed monthly charges is an exercise of monopoly power and impedes the longstanding goal of universal service in the United States. Utilities' concern about loss of revenue is fair, but an SFV model is probably the worst option available by which to address it.

Utility cost recovery and revenue stability can be addressed many different ways, some desirable and some less desirable. In addition to fixed charges, three other options — a higher allowed rate of return, incentive regulation, and revenue decoupling — are discussed below.

In states where revenue regulation mechanisms have not been deployed, but utility revenues are erratic or declining owing to changes in usage, the market will demand a higher return on invested capital. Regulators are effectively letting the capital markets set a **higher rate of return** for the utility. But either a higher return on equity or a higher equity ratio will increase the utility revenue requirement. Thus, this laissez faire approach certainly results in higher costs to consumers over time.

Good rate design addresses the legitimate concerns of all major interests, provides a framework for stable regulation of utilities, and enables the growth of renewable energy and energy efficiency to meet electricity requirements.

Incentive regulation, or performance-based ratemaking, is another way to address the revenue loss that utilities experience if customer sales decline. If the regulator sets the achievement of a defined level of sales reduction from energy efficiency as a goal, and provides a financial reward to the utility for achieving that, the regulator can make up the lost earnings that the utility experiences. The challenge in performance-based ratemaking is to set the objectives for the utility to be achievable but challenging, and to set the rewards to be ample but not excessive.

Revenue-based regulation, or "**decoupling**," is widely used throughout the United States to insulate gas and electric utilities from revenue impacts attributable to sales variations. The essence of revenue regulation is that the utility regulator sets an allowed revenue level, and then makes periodic small adjustment to rates to ensure that allowed revenue is achieved, independent of changes in units (kW and kWh) sold. One benefit of revenue regulation is that the utility normally receives a "formula" to reflect higher costs, such as a "revenue per customer" allowance. These do tend to lead to very small annual increases in revenues. Whether prices increase depends on whether average consumption by customers is rising or declining as the number of customers change. Critics worry that these mechanisms result in annual increases, and that declining costs are not offset against rising costs, but a well-structured mechanism can address these concerns.

A well-designed revenue regulation framework is the best option to address utility revenue attrition that energy efficiency or renewable energy deployment may cause. There is no silver bullet to address the legitimate concerns of all interests. The evidence, however, demonstrates that high fixed charges have the most adverse impacts on consumers, the environment, the economy, and society. Good rate design addresses the legitimate concerns of all major interests, provides a framework for stable regulation of utilities, and enables the growth of renewable energy and energy efficiency to meet electricity requirements.

Good rate design should be accompanied by **bill simplification**. In many states, the utility bill has become a rather dense tangle of line items that represent, in many cases, a long history of policy initiatives and regulatory decisions. To the extent that line items can be eliminated or combined, consumer confusion is likely to be reduced. Utilities should be required to display the "effective" rate to customers, including all surcharges, credits, and taxes, so consumers can measure the value of investing in energy efficiency or other measures that reduce (or increase) their electricity consumption.

As customers utilize greater energy efficiency and deploy more PV, the reductions in their bills can have the effect of allocating greater **cost recovery responsibility** to other customers. This is often described as a cross-subsidy. This is an unfair characterization; in fact, the system for allocating costs among customers and customer classes has always been a dynamic one that reflects the changing characteristics of all customers over time. Still, this is an important issue, and regulators will need to take care in rate design to assure that all customers share in the benefits that industry changes will bring and that no customer group is left out of the mix. This includes customers who may not be in a position to maximize smart grid usage, such as renters. If the rate design for DG customers is implemented according to the principles we have outlined, then non-DG customers should see equitable prices for energy delivered to their meters. By properly implemented, we mean that DG customers are not unduly rewarded for deploying DG; the collateral benefits of DG, such as reduced line losses, deferred and avoided distribution investments, health impacts, and other non-energy benefits are considered; and the potential for overall reductions in the price of generation is accounted for.

Conclusion

Rate design will be an important driver of utilities' success in making the transition to a clean power system. Utilities, customers, and third-party service providers will need the tools to manage the grid as efficiently as possible. Regulators will need to ensure that benefits and costs are fairly allocated. Prices that are accurate and easy to understand can reward customers for energy usage behavior that contributes to the reduction, rather than increase, of utility system costs.

Utility rate designs will have to more appropriately reflect the costs of electricity provided (or merely delivered) by the utility and the benefits that are provided to the utility system by customers. As utilities and third-party vendors develop and offer more innovative technologies (such as smart appliances that can respond to grid pricing signals), pricing will need to become even more geographically, temporally, and functionally granular and precise. Smart rate designs will need to address not only the amount consumed but also when it is consumed and its impact on costs and other customers. In addition to recognizing locational benefits in pricing, good rate design recognizes the attributes that a customer can provide in terms of energy, capacity, and ancillary services.

Rate design will be an important driver of utilities' success in making the transition to a clean power system. Smart rate designs will need to address not only the amount consumed but also when it is consumed and its impact on costs and other customers.

A small number of utilities offer some kind of dynamically priced rate to residential customers, whether it is a TOU rate or a peak-time rebate. However, for policymakers to move forward in the direction of TOU pricing on a larger scale, customer education will be important to empower informed decisions about energy use.

For DG customers specifically, the price they pay or receive for electricity they either consume or provide to the grid respectively will matter greatly in terms of encouraging or discouraging growth. Bidirectional rates with TOU pricing may offer one of the best solutions for this segment of the market. Under this rate design, the DG customer pays the full retail rate for any power consumed, just like any other customer. This customer is then compensated based on the same time periods, either using the retail rate or on a value basis. That value can be based on an analysis of the contribution of DG to the grid and can be set independently by a state public service commission.

Viewed as a quick fix to lost revenues associated with customer engagement in energy solutions, utilities are increasingly proposing SFV rates with high monthly fixed charges. Yet SFV is not a step forward, but a step backward. It discourages innovation and efficiency, penalizes low-income and apartment residents, and results in per-unit prices that fall far short of total system long-run incremental costs. The argument against SFV also follows clearly from the argument against unavoidable, recurring charges generally: it is not justified by fundamental economic principles.

Utilities have a long history of operating as monopolies, but technology means that both they and their regulators must adapt. Utilities may find they need to view their business differently. Power sector transformation will need to incorporate new tools to address this. Rate design will be an important element. The role of regulation in this power sector transformation will be to develop pathways that lead to smarter solutions that optimize the value of interconnection and two-way communication for the customer and the grid. Many of these solutions will be market-driven.

The speed at which change takes place will vary from jurisdiction to jurisdiction and will be influenced by what customers want and the utility culture. Regulators will have an important role to play in overseeing this transformation. In doing so, they should strive to avoid expensive mistakes based on defense of the legacy structure of the industry. Instead, regulators will need to focus on identifying costs and benefits of alternative strategies and seek to maximize the net value to customers and society.

I. Introduction

For most of its history, the electric utility industry saw little change in the economic and physical operating characteristics of the electric system. Large central station generating plants connected to high-voltage transmission delivered power to local distribution grids for delivery to end users, mostly by vertically integrated utilities that owned all of these components. Though reliable and remarkably low-cost, the historical electric system was, and in many ways remains, a black box to both customers and to system operators. Little in terms of the status of the system or customer use of the system was known in real- or near real-time. In short, for an industry in the information age, parts of the electric system can be considered rather "unenlightened."[1]

Today, the industry is facing a number of radical changes that will change this unintelligent landscape. Information systems are coming to the grid that will inform customers and system operators about how the system really works and how actions or failures to act can impact costs to customers and to society. Two categories of these changes will both demand and allow a more sophisticated method of pricing services to customers, a concept generally referred to in the industry as "rate design."

First, end users are installing their own generation, mostly in the form of photovoltaic (PV) systems, and are connecting different types of end-use appliances with increasing "intelligence" built in. Changes in customer usage brought about by energy efficiency and demand reductions in the face of price signals have allowed these phenomena to be recognized as virtual energy resources. In addition, the electric vehicle as a whole new class of end use is poised to grow rapidly over the coming years just as energy storage systems are poised to finally become economical. Together, these and other emerging technologies will usher in an entirely new system planning and operational dynamic. These changes, all at or near the customers' premises, will allow greater control of end-use loads and position the customer to respond to prices and system operational conditions in real-time or near real-time.

Second, utilities are deploying advanced metering, sometimes referred to as "advanced metering infrastructure" (AMI) or "smart meters," and more sophisticated system control and data acquisition (SCADA) systems that will provide system operators a new, real-time understanding of the state of the electric system, as well as the ability to communicate with generators, substations, transformers, meters, and end-use appliances.

To realize the full potential of these new systems and end uses, regulators, utilities, third-party service providers, and customers will need to utilize more advanced rate designs. Most important of these will be the more widespread use of bidirectional, time-sensitive prices that more accurately reflect cost. At the same time, regulators will need to take care to avoid potential pitfalls that would undermine the value of these new technologies.

Basics of Rate Design

Rate design is the regulatory term used to describe the pricing structure used by electric utilities in the United States. It explicitly includes the itemized prices set forth in tariffs and implicitly includes the underlying theory and process used to derive those prices. The *structure* of prices—that is, the form and periodicity of prices for the various services offered by a regulated company—has an impact on the choices made by customers, utilities, and other electric market participants which, in turn, affect resource development and utilization choices. These choices then have indirect consequences in terms of total costs to society; environmental and health impacts; and the overall economy.[2]

1 Those interested in the emerging changes and the challenges they present are invited to go directly to the sections covering Rate Design Principles and Rate Design for Specific Applications.

2 Weston, F. (2000). *Charging for Distribution Utility Services: Issues in Rate Design.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/412

Core Rate Design Principles

As one might expect, although rate design for electric utility customers is of critical importance, it is poorly understood by the general public and often lacks transparency.[3] Yet because customer energy usage choices are affected by the prices they pay, the difference between a progressive and regressive rate design can increase customer usage by as much as 15 percent.[4] Traditional simplistic rate designs that charge a single rate per unit of consumption, or worse, charge a lower rate as consumption increases, are still common in many Central and Southern states.[5] However, those traditional rate designs may not be the preferred rate for consumers, or be in the best interest of the utilities that serve them or society. Things are changing, and the industry must adapt to change or risk the fate of landline telephone companies, which have lost 60 percent of their access lines since the advent of telecommunications competition.

Rate design determines the prices consumers see and use to guide their consumption and investment choices. Prices affect how consumers use the electrical devices, appliances, and systems in our homes and factories. Electricity prices also influence how consumers invest in new equipment and the value consumers obtain from that equipment.

Most people who have ever tried their hands at designing rates for regulated utilities invariably say that it is "more art than science." Because of the shared nature of the system and the need to spread cost recovery fairly among all customers, the idea that rates should be set based on customer cost causation is a foundational concept in rate design. Analysts who ask, in a causal sense, "why" costs are incurred often reach different conclusions than those who measure, in an engineering sense, "how" costs are incurred. Rate design relies in strong measure upon the judicious application of certain economic guidelines. The following elements of economically efficient rate design necessary to address current and coming challenges in the electric industry are based on those laid out in James Bonbright's 1961 *Principles of Public Utility Rates,* and in Garfield and Lovejoy's *Public Utility Economics.* These principles require that rates should:

- Be forward-looking and reflect long-run marginal costs;
- Focus on the usage components of service, which are the most cost- and price-sensitive;
- Be simple and understandable;
- Recover system costs in proportion to how much customers use, and when they use it;
- Give consumers appropriate information and the opportunity to respond by adjusting usage; and
- Where possible, be temporally and geographically dynamic.[6]

Rate design signals public priorities about short-term and long-term economics, including especially the type and pace of future resource procurements. Rates can be designed to meet or, in the case of poor rate design, frustrate public policy objectives to use electricity more efficiently, meet environmental goals, and minimize adverse social impacts, including public health.

Rates are also pivotal in providing utilities the opportunity to recover their authorized revenue requirement. Revenue adequacy is a core objective of rate design, but the more constructive design ideal for rates is forward-looking, so that future investment decisions by the utility and by customers can be harmonized.

Based on these traditional rate design concepts, and looking forward to a world with high levels of energy efficiency, distributed generation, and customer options for

3 This is evidenced by the number of recent rate design reports. See: Rocky Mountain Institute (RMI) eLab. (2014, August). *Rate Design for the Distribution Edge.* Available at: http://www.rmi.org/elab_rate_design#pricing_paper; RMI. (2015, February 26). *Why New Electricity Pricing Approaches are a Sheep in Wolf's Clothing* [Blog post]. Available at: http://blog.rmi.org/blog_2015_02_25_why_new_electricity_pricing_approaches_are_a_sheep_in_wolfs_clothing; and Tong, J., and Wellinghoff, J. (2015). Why fixed charges are a false fix to the utility industry's solar challenges. *Utility Dive,* February 13, 2015. Available at: http://www.utilitydive.com/news/tong-and-wellinghoff-why-fixed-charges-are-a-false-fix-to-the-utility-indu/364428/.

4 See Lazar. J. (2013). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Montpelier, VT: The Regulatory Assistance Project. http://www.raponline.org/document/download/id/6516. Appendix A provides a calculation of how rate design can influence consumption.

5 Worse, in that new generation, transmission and distribution resources accelerated by declining block rate designs, cost more than older resources. Also, utility capital cost forecasts are rising as are environmental costs.

6 Lazar, 2013, p. 10.

on-site backup supply, modern rate design should adhere to three basic principles:

- **Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.**
- **Principle 2: Customers should pay for grid services and power supply in proportion to how much they use these services, and how much power they consume.**
- **Principle 3: Customers that supply power to the grid should be fairly compensated for the full value of the power they supply.**

These principles and priorities should be reflected in smarter rates designed to maximize the value of technology innovations, open up new markets, and accommodate the distribution and diversification of customer-sited generation resources. This necessarily includes consideration of what those future technologies and policies could look like, with a focus on metering, market structure, and pricing. In particular, consideration of how rates provide a "price signal" to customers, utilities, and other market participants to inform their consumption and investment decisions regarding energy efficiency (EE), demand response (DR), and distributed generation (DG), collectively referred to as distributed energy resources (DER).[7]

7 Quite a bit of background is necessary to fully appreciate the nuances of current practice, and the path to future rate designs. The reader is directed to the Guide to Appendices at the end of this document for more in-depth treatment of these issues.

II. Current and Coming Challenges in Utility Rate Design

Customer-Sited Generation

Over the past two decades, federal, state and local policymakers have implemented policies that have spurred the development of customer-sited DG, in particular, customer-sited PV systems. The policies include federal tax credits, state renewable portfolio standards (RPS), net metering, and interconnection standards.[8]

As the costs of renewable and other DG technologies have decreased, the options available to customers to procure these technologies have increased.[9] In addition to PV, other technologies available to customers are typically renewable and consist of wind turbines, small hydro, biomass, efficient cogeneration, fuel cells, and battery storage.[10] PV has been deployed by large industrial, commercial, residential, and other customers. For large commercial and industrial customers — any customers utilizing large amounts of heat for processing — combined heat and power (CHP) projects are commonly used to increase the efficiency of energy production by turning waste heat from industrial or manufacturing processes into electricity or, conversely, turning waste heat from electricity generation into process heat for industrial and manufacturing uses.

All of these resources reduce the electric grid's environmental footprint and provide a hedge against volatile fuel prices.[11] In addition, DG systems are decentralized, modular, and more flexible technologies that are located close to the load they serve. This reduces loads on transmission and distribution lines, transformers, and substations, which, in turn, reduces losses on the system, extends the life of equipment, reduces the risk of equipment failure and power outages, and can, if located at strategic points on the system and at the right time, defer or avoid system equipment replacements and upgrades. Customers can typically purchase or lease DG from a third party, often with seller or third-party financing.

Increasing penetrations of distributed renewables, especially PV, are changing the dialogue on how to fairly compensate providers of these resources (DG customers) and utilities for the services and benefits they each provide. PV is by far the most common form of customer-sited generation resource in terms of numbers of installations, and its adoption is already changing the relationship between utilities and consumers. Rate design must efficiently and fairly incorporate DG contributions to the grid, as well as fairly allocate the benefits and costs of their use for DG customers and for the grid.

At low levels of installation of distributed renewables (under 5 percent of customers), few if any, physical modifications are required to electric distribution systems. Power produced by a PV customer either serves the customer's own load or that of neighbors served by the

8 Steward, D., and E. Doris, E. (2014, November). *The Effect of State Policy Suites on the Development of Solar Markets.* National Renewable Energy Laboratory (NREL), Technical Report NREL/TP- 7A40-62506. Available at: http://www.nrel.gov/docs/fy15osti/62506.pdf. See also the Energy Department's SunShot Initiative, which is a national effort to make solar energy cost-competitive with traditional energy sources by the end of the decade. Through SunShot, the Energy Department supports private companies, universities, and national laboratories working to drive down the cost of solar electricity to $0.06 per kilowatt-hour. Learn more at http://www.energy.gov/sunshot.

9 National Renewable Energy Laboratory. (2012). *Renewable Electricity Futures Study.* Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; Sandor, D. eds. 4 vols. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/re_futures/.

10 US Department of Energy (DOE). (2007). *The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion.* Available at: http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Report_-final.pdf

11 There are other non-energy benefits, such as reducing manufacturing costs, which is good for economic development.

same substation bus. At the distribution substation, all that is observed is a lower overall load during the solar day. This is the situation in most of the United States. The low penetration scenario changes once solar output exceeds total load on a given substation. This is being experienced in Hawaii, which has the highest PV penetration of any state and where over 10 percent of residential consumers have PV systems installed. In the single-family residential sector, it is more than 20 percent in many neighborhoods. At this level of solar saturation, changes to distribution systems may be needed.

Solar penetration is measured in several ways: percent of customers, installed capacity as a percentage of peak demand, or installed capacity as a percentage of the minimum daytime load. Figure 1 is a map of the island of Oahu (Honolulu), showing which circuits have high levels of solar saturation; over half of the residential circuits have installed solar capacity in excess of 100 percent of the minimum daytime load. Therefore, it is possible (depending on the consumption of the customers that have the solar systems) for the customers' local distribution circuit to be delivering power upstream through the substation, rather than the traditional downstream flow of power from generation to transmission to distribution circuits.

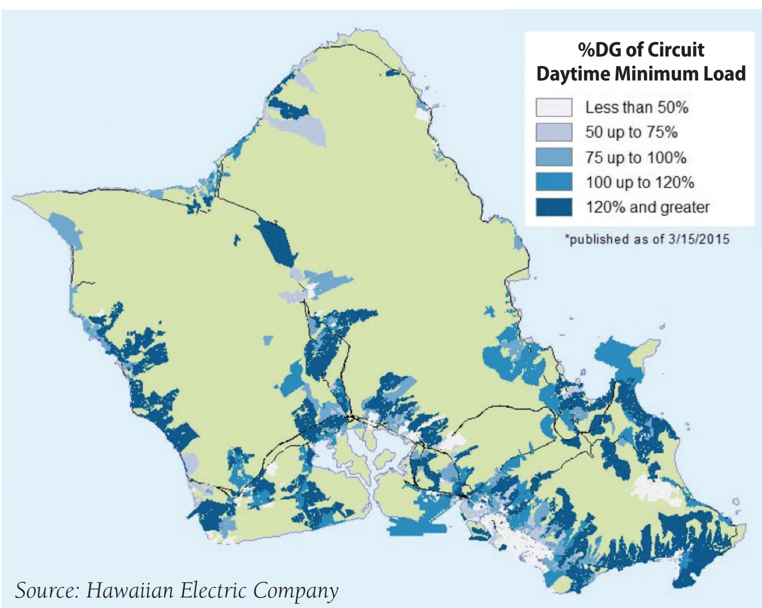
Once solar penetration reaches about 10 percent of customers, as it has in Hawaii, there may be specific costs to the grid operator, such as additional voltage regulators, that are attributable to high levels of solar penetration. This does not necessarily mean that solar customers should pay different or additional charges compared with non-solar consumers because in most cases this solar penetration is helping to avoid other offsetting generation, transmission, and distribution costs.[12]

Hawaii is serving as a laboratory as it adapts to a high-renewable environment, with a mix of geothermal, hydro, biomass, wind, and solar making up an increasing percentage of electricity supply. The primary utility networks in the state recently submitted two important studies to the state PUC, addressing both distribution[13] and generation[14] planning. With the changes identified in these plans, Hawaiian Electric anticipates being able to adapt and ensure a reliable future with 65 percent renewable energy by 2030, and the state of Hawaii has adopted a legislative standard of 100 percent renewable electricity by 2045.

Adaptations that Hawaii is exploring and implementing include upgrading distribution system components such as higher capacity line transformers, increasing circuit capacity, adding voltage regulation, updating substation equipment, and investing in flexible generation to replace older units that must run continuously to be available to provide service during key hours.

Figure 1

Oahu PV Installations as Percent of Minimum Daytime Load



Source: Hawaiian Electric Company

12 Also, among two solar installations, a solar installation with a smart inverter that can provide ancillary services to the grid may provide the grid with more value than a PV installation with a standard inverter. For more detail on the benefits of solar PV, see: RMI. (2013). *A Review of Solar PC Benefit & Cost Studies,* second edition. Available at: http://www.rmi.org/cms/Download.aspx?id=10793&file=eLab_DERBenefitCost-Deck_2nd_Edition&title=A+Review+of+Solar+PV+Benefit+and+Cost+Studies

13 Hawaiian Electric Company. (2014, August 26). *Distributed Generation Integration Plan.* Available at: http://files.hawaii.gov/puc/4_Book%201%20(transmittal%20ltr_DGIP_Attachments%20A-1%20to%20A-5).pdf

14 Hawaiian Electric Company. (2014, August 26). *Power Supply Improvement Plan.* Available at: http://files.hawaii.gov/puc/3_Dkt%202011-0206%202014-08-26%20HECO%20PSIP%20Report.pdf

Electric Vehicles

Electric vehicles (EVs) are a small part of the electricity load currently, but growth in electric vehicles is likely for many reasons. First, the cost of batteries is declining, and this cost has historically been a major barrier to the EV market. Second, the evolution of the self-driving car is likely to stimulate a greater market for simple vehicles that can be remotely operated. EVs may be well-suited for this market segment.[15] Finally, emissions regulations are pressuring the industry to find zero-emissions transportation solutions.[16]

Electric vehicles such as the Nissan Leaf and Ford Focus can travel three to four miles per kilowatt-hour (kWh), meaning that ten kWh is functionally equal to one gallon of gasoline. An electric vehicle that travels 10,000 miles per year (800 miles per month) will use 3,000 to 4,000 kWh per year, about equal to the annual usage of a residential electric water heater or central air conditioner.

Because of the presence of batteries in the vehicles and the ability to control the timing of when they are charged, EV loads can be very different from traditional loads. If the vehicle battery capacity is adequate for a day's driving (less than 80 miles for the vast majority of drivers), the batteries can be charged at night or at other times when power is plentiful and lower cost, and impose little or no incremental peak demand for the utility system. They can even be controlled by smart transformers connected to smart grid distribution automation systems so that, in aggregate, they impose the minimum load on the system during primarily night-time charging hours.[17] However, encouraging that behavior means that rates should be designed to provide an incentive for EV owners to charge their cars when power costs are low and distribution system capacity is not congested. This requires time-sensitive pricing, a topic discussed in greater detail later in this paper.

Microgrids

Definition

In the near future, utilities will need to interface with customer- or community-owned microgrids. These may range from an individual apartment building or office complex with on-site generation to a municipal electric utility connected to an adjacent larger utility.

Lawrence Berkeley National Laboratories (LBNL) has defined a microgrid as "a localized grouping of electricity sources and loads that normally operates connected to and synchronous with the traditional centralized grid (macrogrid), but can disconnect and function autonomously as physical and/or economic conditions dictate."[18] Large hotels and hospitals, and an increasing number of individual homes, have had on-site emergency generation for decades, but generally fall short of the definition of a microgrid due to lack of communication and control technologies to interact in a bidirectional manner with the grid. But technological progress will potentially extend implementation of this microgrid concept to thousands of customers on each major utility, and millions nationwide.

Residential Microgrid

The visual representation in Figure 2 depicts an example of a residential microgrid as envisioned by LBNL.

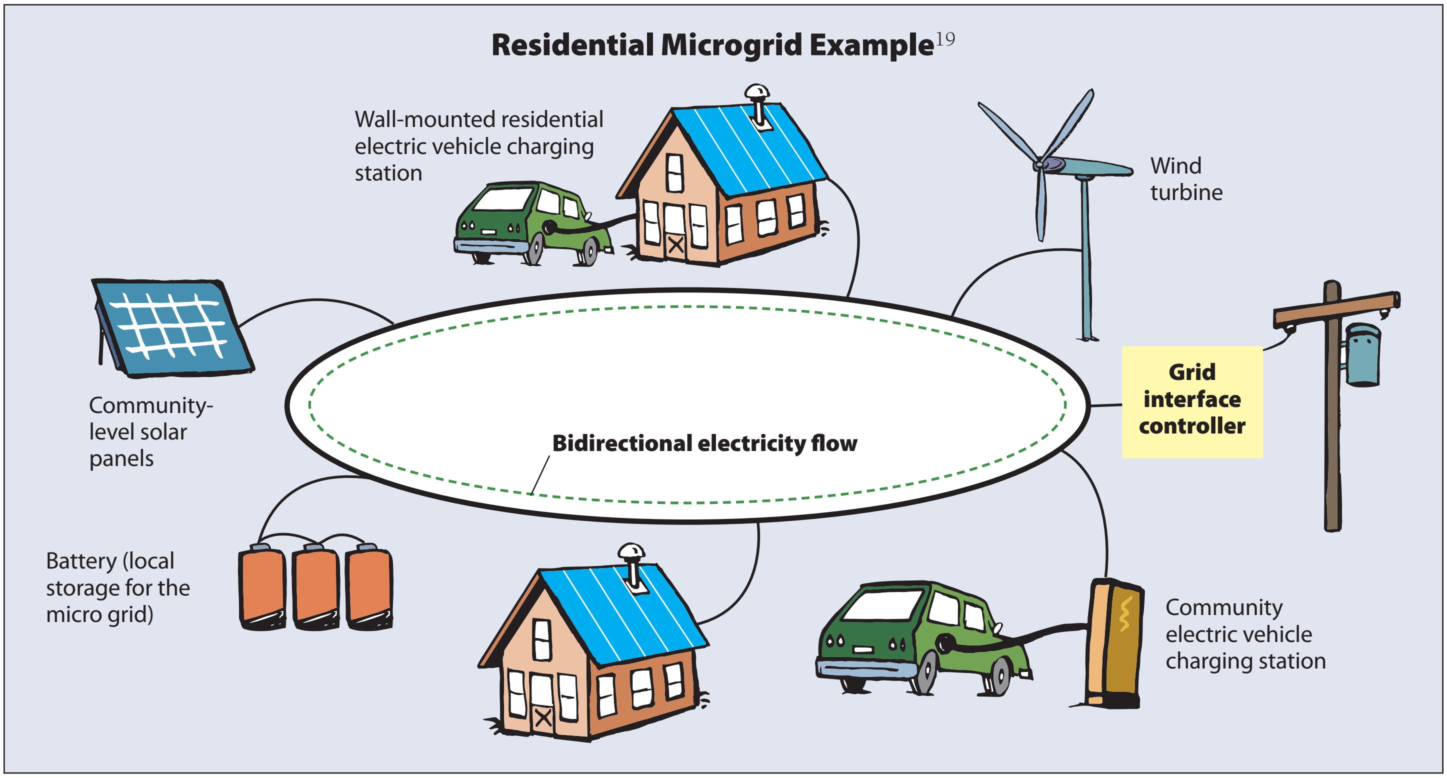
15 Lantry, L. (2015). The Car of the Future Will Be All Electric and Self-Driving. *EcoWatch*. Available at: http://ecowatch.com/2015/06/17/car-of-future-electric-self-driving/

16 This section is primarily extracted from a larger publication on electric vehicles, MJ Bradley & Associates. (2013). *Electric Vehicle Grid Integration in the US, Europe, and China.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6645

17 Hilshey, A.D. (2012). *Electric vehicle charging: Transformer impacts and smart, decentralized solutions.* University of Vermont School of Engineering. Power and Energy Society General Meeting, Institute of Electrical and Electronics Engineers (IEEE), 2012. Available at: http://www.uvm.edu/~prezaei/Papers/Hilshey_GM2012.pdf

18 Lawrence Berkeley National Laboratory (LBNL). *About Microgrids.* Available at: https://building-microgrid.lbl.gov/about-microgrids

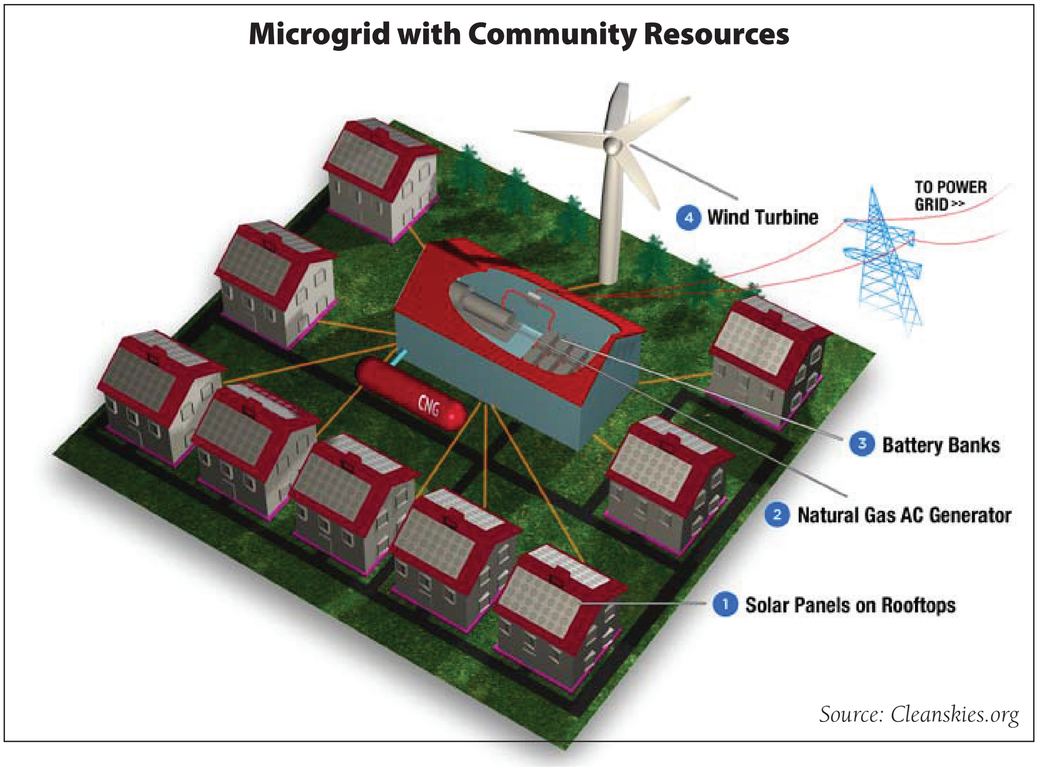
Figure 2



Microgrids with Community Resources

In the near future, whole communities may be planned around a microgrid concept, with single- and multi-family housing constructed with smart meters and smart appliances. These microgrids may utilize DG (both individual- and community-owned) and storage technologies as shown in Figure 3. Microgrids will depend on utilities for some service at appropriate rates; however, microgrids will also provide services to utilities at times, and so the compensation framework needs to be symmetrical and bidirectional.

Figure 3



Source: Cleanskies.org

19 University of California at Irvine. Cyber-Physical Energy Systems (CPES). Available at: http://aicps.eng.uci.edu/research/CPES/ (2014).

Storage

Table 1

Functional Attributes of Storage

Electric energy time shift	Time-of-use energy cost management
Electric supply capacity	Demand charge management
Load following	Electric service reliability
Area regulation	Electric service power quality
Electric supply reserve capacity	Enabling consumers to serve dedicated loads with specific types of resources
Voltage support	Renewable energy time-shift
Transmission support	Renewables capacity firming
Transmission congestion relief	Wind generation grid Integration (short-duration discharges)
Transmission and distribution (T&D) upgrade deferral	Wind generation grid integration (long-duration discharges)
Substation on-site power	

Source: Pomper, NRRI, 2011

Storage technologies can be a game changer if they are distributed in communities, interconnected with a smart grid, and not price prohibitive.[20] Cheap and reliable thermal or electricity storage alters the existing electric grid paradigm by allowing immediate balancing of the system without needing to cycle power plants. In this sense, DG customers with storage can provide peak power anytime, as bubbles of renewable supplies can be stored until a later, more valuable time period. From a system operations point of view, energy supply (generation) and loads (end uses) must be instantaneously kept in balance, even as customers change their end uses. This is currently done primarily by designating one or more generators to increase or decrease output in response to changes in load. The presence of significant storage on the system would allow generators to generate when they can, while allowing the storage technology to provide additional energy or absorb additional energy as loads change. Storage is a multi-attribute resource that can serve this and many other functions as outlined in Table 1.[21]

Storage allows customers with DG resources to go off-grid if utility rate designs create an economic signal to customers that it is cheaper to completely disconnect from the grid than it is to use the grid as a backup system.[22] Storage technologies are expected to be developed both at utility scale and at the individual customer scale.

If significant numbers of customers install storage and disconnect from the grid, then this storage is not available to the grid operator for optimal management for the benefit of all electricity users. If this occurs, an expensive augmentation to the grid will be poorly utilized. If these customers remain grid-connected, their storage can be used not only for their own benefit, but also potentially for broader public benefit. The existence of storage may also make those customers' loads available for demand-response programs.

The simplest energy storage technologies are thermal and mechanical storage systems, including:

- Electric water heaters controlled to operate during low-cost hours and hold that hot water for later usage or operated in a coordinated manner to minimize their aggregate load at any point in time, thus reducing system costs and increasing system reliability;
- Ice storage systems to store "cold" to provide air conditioning when needed; and

20 "Storage" involves a series of acts: converting grid-interconnected electricity to another form of energy, holding that other form of energy for future use, and then converting it back to grid-interconnected electricity at a different time. The individual acts that comprise this series may be referenced as, respectively, "charging," "holding," and "discharging." See Pomper, D. (2011, June). *Electric Storage: Technologies and Regulation.* National Resource Regulatory Institute (NRRI), p. 3. Available at http://www2.econ.iastate.edu/tesfatsi/electricity_storage_manual.RGuttromsonJuly2011.pdf. To this should be added other forms of energy storage, such as water heater controls, water system reservoir management, and air conditioning thermal storage, which may provide lower-cost means to shape loads to resources and resources to loads.

21 Pomper, 2011, p. 9.

22 Utility rate designs should not create an artificial incentive for complete separation from the grid by small-use customers, potentially triggering a spiral of customer grid defection (e.g., see the discussion of straight fixed/variable pricing later in this paper and Appendix D).

- Mechanical storage systems that spin a flywheel, compress air or another vapor, or raise a weight when power is cheap to provide end-use service power at a later time.

Some other types of electricity storage technologies are utility-pumped storage, chemical batteries, and super capacitors. Unfortunately, these types of electricity storage have over recent history been very expensive, ranging from $60/kWh to $860,000/kWh of daily storage capacity depending on the technology.[23] However, there is excitement in the storage world that costs may soon be driven down, given the partnership between Tesla cars and Solar City to provide backup systems for PV owners. Because they necessarily come with batteries, EVs represent a potential means of electricity storage for both customers and for the grid as a whole. The limited driving range of the current supply of EVs means they have limited capacity to serve as whole-house backup systems; however, Toyota already sells such a vehicle in Japan, spurred to market after the tsunami of 2011.[24] In addition, the development of cheaper battery technology for vehicles will likely be transferred to stationary storage systems for customers and utilities; the recent announcement by Tesla of the residential "Powerwall" battery is an initial step in this direction.[25]

In 2014, about one out of five household PV systems in Germany was sold with a battery pack, and that is projected to be one in three in 2015.[26] Costs are headed down, with Bloomberg New Energy Finance predicting that residential-scale battery storage costs will fall 57 percent by 2020. Lux Research sees the global market for PV systems combined with battery storage growing from the current $200 million a year to $2.8 billion in 2018.[27]

Although it is relatively inexpensive to install limited storage to mitigate the afternoon and early-evening impact on utility peak, it is more expensive (though getting cheaper) to install sufficient storage to enable complete disconnection from the grid. Utility rates should be

Pedestrian Crossing Signals: Example of Widespread Grid Defection

The earliest economic applications of solar with storage were for remote applications, including military and national park sites where extending grid service was prohibitively expensive.

This has expanded in recent years to low-level uses of power where even a short utility line extension and billing account exceed the cost of a solar panel and battery. For example, tens of thousands of pedestrian crossing signals are being installed in urban areas with this technology, despite being adjacent to grid electric service. Low-wattage LED light bulbs, coupled with cheaper solar panels, make it cost-effective to leave out the cost of a grid connection.

The threshold size at which grid independence makes sense is a function of two interacting costs: the cost of a stand-alone system and the charges that utilities make for grid service. If the fixed charges for grid services rise, the number of applications where grid independence is economical will rise.

Graphic from: www.xwalk.com

23 Pomper, 2011, pp. 17-20

24 Carter, M. (2012, June 5). Toyota Develops System that Enables Electric Vehicles To Power Your Home. *Inhabitat.* Available at: http://inhabitat.com/toyota-develops-system-that-enables-electric-vehicles-to-power-your-home/

25 See Powerwall. *Tesla Home Battery.* http://www.teslamotors.com/powerwall. A 10 kWh system will be for backup applications will be available in the summer of 2015 for $3,500. It comes with a ten year warranty but installation and inverter costs are additional. Such a system in Southern California, under a time-differentiated rate design, is estimated to have a five-year payback. Also see: Teslarati. (2015, May 2). *A Tesla Powerwall-Powered Home: Will It Pay Off?* Available at: http://www.teslarati.com/tesla-powerwall-home-will-it-pay-off/

26 Deign, J. (2015). German Energy Storage: Not for the Fainthearted. *Greentech Media,* March 13, 2015. Available at http://www.greentechmedia.com/articles/read/german-energy-storage-not-for-the-faint-hearted. "The cost of combined PV-and-battery systems runs from about €13,000 to €25,000 ($13,800 to $26,600). Batteries make up about 30 percent of the total bill."

27 Guevara-Stone, L. (2014). Solar City and Tesla shine spotlight on solar-battery systems. *GreenBiz,* January 16, 2014. Available at: http://www.greenbiz.com/blog/2014/01/16/solarcity-and-tesla-shine-spotlight-solar-battery-systems.

structured to encourage cost-effective storage solutions (e.g., through the use of time-varying rates).

Distributed Ancillary Services

The presence of generation, storage, and smart control technologies at customer premises offers the opportunity for customers to provide a number of valuable functions to the grid. These generally fall into a category termed "ancillary services" and include voltage regulation, power factor control, frequency control, and spinning reserves.[28] In addition, where system operators or third-party aggregators have the ability to control end-use loads, customer appliances can deliver demand response during high-cost periods or when the grid is at or near its operating capacity and may be at risk for system failures. Demand response, in addition to being an economic response by customers, becomes a form of spinning reserve when placed at the disposal of system operators.

28 Spinning reserves refer to the availability of additional generating resources, which can be called upon within a very short period of time. Different utilities and different utility markets utilize varying response time frames to define spinning reserve services, ranging from instantaneous to up an hour or so.

III. Rate Design to Enable "Smart" Technology

Survey of Technology

The traditional electric utility is undergoing fundamental change. Utilities from Maine to California have deployed smart grid upgrades or are beginning the transition to a smarter grid.[29] These upgrades promise to deliver an entirely new level of information about system operations and consumer behavior. In short, the information age is coming to the electric industry.[30] Computerizing the traditional grid with AMI and advanced SCADA systems will enable the development of new and dynamic rate offerings. Meanwhile, smart home appliances that can automatically respond to prices or be dispatched by system operators or third-party service providers will assist customers in managing their usage and minimize total system costs and increase system reliability.[31] These new smart technologies will also help accommodate customer-owned generation, utility-scale renewable power, energy storage (both customer- and utility-scale), electric vehicles, and microgrids.

Various technology enhancements can improve the effectiveness of more complex rate designs, by enabling customers to respond to prices automatically. Some examples include:

- **Smart thermostats:** Can automatically change heating and cooling settings in response to real-time price changes, while allowing the consumer to manually override these. The Nest, SilverPAC Silverstat 7 Advanced, and GE Nucleus are examples of thermostats with that capability. Good pricing can be supplemented by good utility or regional wholesale power market entity programs that offer curtailment inducements based on grid value.
- **Grid-integrated water heating:** Can automatically increase hot water storage during low-cost periods, curtail water heating operation during high-cost periods, and also supply ancillary services to the utility without the consumer even noticing that this is happening. Great River Energy, serving electric cooperatives in Minnesota, is currently demonstrating this potential.[32]
- **Electric vehicle chargers:** Can be programmed to provide "economy" charges, allowing the customer to take advantage of low-cost energy when it is available.
- **Vehicle-to-grid applications:** Can enable EV batteries to flow power back to the grid during critical hours, essentially allowing the grid operator use of the EV batteries and provide a means of compensation to EV owners for supplying the energy.[33] A pilot program is underway in Maryland and Delaware to enable vehicle-to-grid service.

Smart Meters

Smart meters provide data acquisition, equipment control and communication capability between the

29 The term "smart grid" is used here broadly to include both utility grid-side and customer investments.

30 Determining whether AMI and smart grid are projected to be cost-effective before deployment is an important consideration and one that is beyond the purview of this report. A good discussion on smart grid benefits and costs can be found in Alvarez, P. (2014). *Smart Grid Hype & Reality.* Wired Group Publishing, Chapters 4-9.

31 PR Newswire (2013, January 8). *ComED Launches Smart Home Showcase Contest.* Available at: http://www.prnewswire.com/news-releases/comed-launches-smart-home-showcase-contest-186025412.html

32 Podorson, D. (2014, September 9). *Battery Killers: How Water Heaters Have Evolved into Grid-Scale Energy-Storage Devices.* E Source White Paper. Available at: http://www.esource.com/ES-WP-18/GIWHs

33 EV World. The V2G Revolution Gets a Textbook [Podcast]. Available at: http://www.evworld.com/article.cfm?storyid=1675

customer and the power grid, plus outage detection and reduced meter reading costs.[34] Smart meters are able to record customer usage at a fine timescale and then communicate that information back to the utility and to the customer. This information can, in turn, be used to control end-use appliances in response to price signals and system conditions. When used by system controllers, they can aid in reducing loads during times of system stress, thereby reducing losses on the system and wear and tear on equipment. This will help to avoid system failures and outages. When employed by the customers or on their direct behalf, smart meters can be used to shift usage from high-cost periods to periods when lower cost energy is available.

Smart Meters for Distributed Generation

Customers with PV systems or other on-site grid-interconnected generation or battery storage systems both take power from the grid and deliver power to the grid. Keeping track of these flows is necessary for accurate billing and crediting of services provided to the grid at different times of the day when the value may be very different. Smart meters have this capability, and are needed when the rate design requires knowing when power is flowing and in which direction, to more accurately value the cost of customer use and the value of customer production. Figure 4 shows the kind of data that a smart meter can record for a home with a PV system; the red shows the total on-site consumption of electricity (including sporadic 4 kW spikes of an electric water heater), and the green shows the production of PV power. Where the green exceeds the red, the customer is a net exporter to the grid. Clearly if the customer is consuming most of its power during off-peak periods, and supplying power mostly during on-peak periods, the solar customer is providing significant value to the grid that is not captured by simple monthly kWh net energy metering (NEM).[35]

Remote Disconnection and Reconnection: Challenge and Opportunity

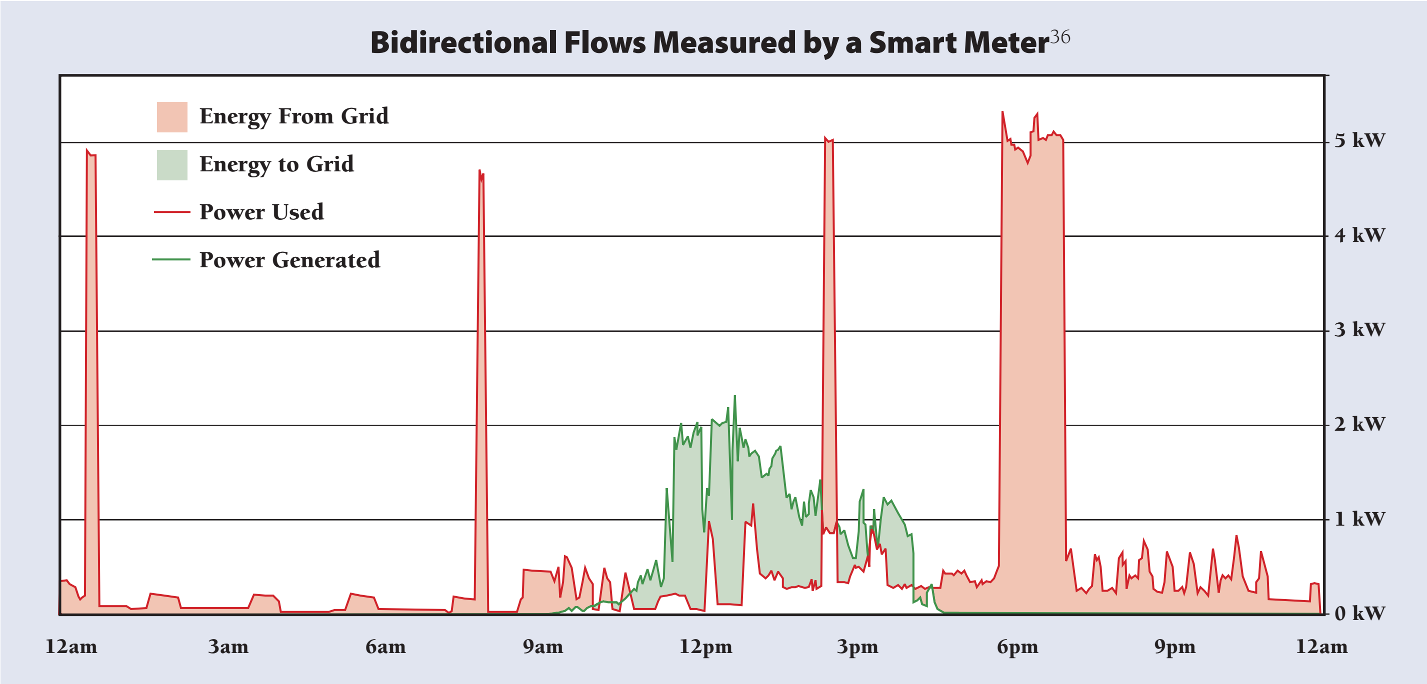
Without smart meters, when utilities disconnect service (move -out, or non-payment), they must send a service person to the premises to lock out the meter. This has a cost, normally recovered through a levy on the individual consumer. Where disconnections are effected for non-payment, it often (depending on regulatory commission rules) involves three site visits, one to post the notice of impending disconnection, one to effect disconnection, and a third to reconnect. The second and third site visits reduce the likelihood of disconnection by providing an opportunity for the consumer to make a payment at the site to avoid disconnection. With smart meters, the disconnection and reconnection can be done remotely. This has an economic benefit, but raises a social equity concern. The challenge is to realize the operational benefit of the remote disconnect and reconnect while maintaining safeguards for vulnerable populations.

Low-income advocates have a concern about this capability, because disconnection can be done without any site visit, and customers with medical needs, or who have the ability to make a field payment, are disconnected. Some utilities with remote disconnect capability have addressed this by having the site visit performed by a (lower paid and more customer-oriented) customer service agent who is better able to judge an exception or accept field payment, rather than by a (more technically trained) electrical worker. This can provide lower costs and better service than previous approaches, and avoid one or two site visits. In any event, with remote reconnection, it is possible for a customer to phone in a payment, and have service restored immediately. Regulators are becoming aware of both the promise and pitfalls of this remote capability. In some foreign countries, money transfer via prepaid cellular phone systems enables immediate payment even for consumers without credit cards or bank accounts. Further, the charge for of disconnection and reconnection to the consumer should be dramatically reduced to reflect the reduced costs to the utility.

34 They also provide operational benefits such as reduced meter reading costs and outage detection.

35 “Net energy metering” is a pricing scheme that “pays” for the output of customer-sited generation at the same rate that the customer pays for energy delivered from the electric system.

Figure 4



Smart Homes and Buildings

Smart homes and buildings are structures in which end uses such as heating, ventilation and air conditioning (HVAC); water heaters; and lighting systems are controlled by intelligent networks to minimize cost. Smart building end-use appliances may also respond automatically to conditions within the building by providing lighting or space conditioning only when people are present or reducing load in response to price signals received from the grid operator.

Smart Appliances

Smart appliances include the building systems noted above, as well as such other items as refrigerators, washers and dryers, computers or any other appliance equipped to communicate with smart grid control systems. Some smart appliances will be programmed to act on their own, based on information they can garner from their interconnection to an information system and customer preferences. Others will be controlled by other systems such as home energy management systems or demand response aggregator controls, which gather that information and provide the decision-making software.[37]

SCADA and Meter Data Management Systems

From a system management and operations standpoint, much of the electric utility system remained unchanged from its early 20th century condition until the introduction of SCADA systems late in the century. SCADA systems enabled grid operators, for the first time, to see how their systems operate at a more granular level and in real or near-real time. The addition of smart meters and other devices, collectively referred to as the "smart grid," promises to vault the level of sophistication to an even higher level. A key element of any smart grid deployment is the information system that collects data from smart meters and other measurement and control devices and transmits it to the utility. It is also used to communicate back to the customer and, increasingly, directly to customer appliances and third parties such as curtailment service providers.

A meter data management system (MDMS) enables the utility to aggregate the data of individual customers' usage at the service, transformer, and circuit level, to identify where demand response measures may be valuable, where distribution system upgrades are necessary, and where specific loads such as electric water heaters and electric

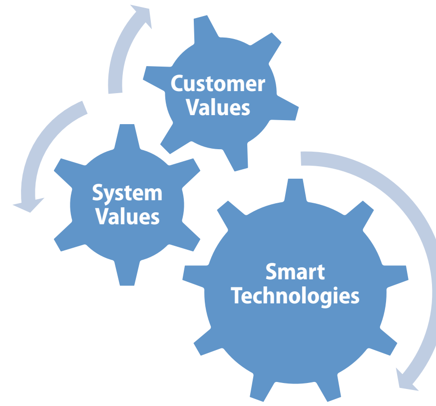
36 Courtesy of Convergence Research; the customer-identifying data has been removed to product the consumer's privacy.

37 Master meter buildings are the scourge of "smart" since the owner is not the user and so preferences can be ignored. They represent an interesting challenge to create programs to help overcome this gap, which may include deploying technology throughout the structure.

vehicles are affecting grid adequacy and efficiency. This improved information analytical capability will provide feedback to enable more clearly defined rate designs that are tied to specific operational and cost-containment goals and to assist utilities, customers, and other service providers to control end uses. Appropriate rate design strategies are also needed for the recovery of the costs of these new systems.

Dynamic Integrated Distribution Systems: Putting All the Pieces Together

Smart technologies enable distribution optimization in many ways. At an operational level, system operators have better situational awareness of the condition of the system at all times and a greater ability to modify those conditions to reduce costs and improve power quality and reliability through strategies like conservation voltage reduction and volt-VAR (volt-ampere reactive) optimization that save energy, and therefore money and resources.[38] In the longer term, smart technologies allow utilities to better assess when and where to make system upgrades or to engage in anticipatory maintenance or replacement of plants to reduce costs and improve reliability. Rate design will play a key role in bringing customer end uses into the toolbox of solutions for these issues. In addition, good rate design will inform the customer about opportunities to save money and to be rewarded for providing value to the overall grid. Poor rate design can impair this ability and prevent the true value of smart technologies from being realized, clogging the gears of this dynamic.



If rates provide appropriate rewards for locational value and ancillary services, costs can be reduced. Pragmatically, rates to consumers need to be relatively simple to be understood, but rates to aggregators of demand response and ancillary services can be more complex and temporally and geographically granular.

38 Energy savings were 2.5 percent in Xcel's SmartGridCity Demonstration Project. See Alvarez, 2014, p. 134.

IV. Rate Design Principles and Solutions

Traditional Principles

The design of rates begins with a functional evaluation of the costs incurred by the utility to provide service to its customers. A foundational notion of rate design is to charge customers in relation to the costs incurred to serve them. A critical step is the allocation of costs among different customer classes — residential, commercial, industrial, and others. Customer cost allocations determine what piece of the utility revenue requirement pie a specific class will be charged. In reaching a cost allocation determination, regulators usually will consider different approaches (embedded cost vs. marginal cost, single peak hour or multiple peak hours,[39] etc.) and review different cost of service studies. The end result is often some blend of the different approaches that hopefully match the overarching priorities of the state. Given the judgment involved, no single approach can be said to be "correct"; rate making is partly science and partly art. Appendix A of this paper "Dividing the Pie," addresses these ideas in more detail.[40]

Rate design involves the definition, allocation, and recovery of customer costs, distribution costs, power supply and transmission costs, and other general costs incurred by the utility to provide service to customers.

Customer Costs

Rate design necessarily involves tying cost causation to the type of price used to recover that cost. A simple example would be the use of a per-kWh charge for fuel costs, which reflects the fact that, as more kWhs are consumed, more fuel is consumed. In the case of customer costs, the inquiry focuses on those costs that vary with the number of customers served. This includes such costs as metering, billing and collection, and customer assistance. These costs are always quite small, typically amounting to no more than $5 to $10 a month per residential consumer.

The fixed charge for residential or commercial service should not exceed the customer-specific costs attributable to an incremental consumer. For urban and suburban residential consumers, this is the cost of a service drop, the portion of the meter cost directly related to billing for usage, plus the cost of periodic (monthly, bimonthly, or quarterly) billing and collection. Monthly billing is usually desirable, because with less frequent billing customer bills become large and potentially unmanageable. However, the size of the bills is driven by usage levels, not merely a cost of connecting to the system; thus, even the cost of billing has a usage-related component, which should be recovered in volumetric prices.

AMI enables a wide array of functions unassociated with metering or billing and collection. The role of AMI in peak load reduction, energy efficiency, system operations and reliability, and other functions of the utility clearly establish that smart meter costs do not belong exclusively in the category of customer-related costs. The incremental cost of smart meters, above and beyond what would have to be spent for older style meters, should be recovered through the same pricing mechanisms used to recover other costs associated with those other functions, and a portion of the net benefit that smart meters provides should be applied to *reduce* customer-related costs. If regulators treat smart meter costs in the same manner as traditional meters — apportioning the costs on a per-customer basis — they are ignoring a cost-follows-benefit principle.

Other cost minimization strategies may be applied to billing as well. Many banks, brokerages, and other businesses offer a discount to customers that choose electronic billing and auto-payment options; the same discounts may be extended to customers of utilities, helping to reduce the monthly billing-related cost of electricity services that is often reflected in customer charges.

39 Coincident peak (CP) is a measure of peak demand that can be as narrow as the highest single hour (1CP), the average of the four summer monthly peaks (4CP) or the average of 12 monthly system peak hours (12CP).

40 Appendix A explores how the assumptions made in the cost-allocation process can influence rate design decisions.

Distribution Costs

The basic distribution infrastructure — poles, wires, and transformers, plus associated maintenance costs — comprises approximately one-quarter of the revenue requirement for the typical electric utility. Although many utilities view these as "fixed costs," in the long run all costs are variable. Customer usage levels may change dramatically over time and there may be operational alternatives increasingly available such as on-site generation and storage. With the experienced and anticipated reduction in cost for these alternatives, the likelihood of their deployment and use will only increase, making possible the deferral or avoidance of distribution infrastructure investment. At the same time, as customer usage grows within any portion of the distribution system, upgrades and expansions will be required, resulting in greater capital and operating costs. Accordingly, it is important to recover distribution costs on the basis of the end-use consumption and, only where DG penetration is very high, consider specific additional investment in distribution facilities.

Flat Rates

The simplest form of rate design is the flat rate, which is derived by simply dividing the revenue requirement for a given class of customers by the kilowatt-hour sales, and charges a purely volumetric price.

A very important principle of rate design is to align the incremental price for incremental consumption with long-run incremental costs, including societal costs. As discussed earlier, this means that a price reflects the cost of a new renewable energy resource (or a conventional resource plus full environmental damage costs), plus the transmission, distribution, and other utility services needed to deliver that to a consumer.[41] Use of short-run costs, dispatch modeling, or a non-renewable resource as the basis for "incremental cost" is inappropriate and misleading to the consumer and society because it fails to recognize the real costs associated with plant investment and resource choices, many of which have long-term consequences on the order of a half-century or more. The issue of whether societal costs are recovered in the utility revenue requirement is immaterial to setting the incremental price correctly to guide efficient consumer response. This is one reason many utility regulators have implemented inclining block rates — to reflect both utility costs and societal costs in the incremental price per kilowatt-hour.

Demand Charges

Demand charges are sometimes used to recover the non-fuel costs of generation, transmission, and distribution of large commercial and industrial customers. These demand charges have typically been applied to the individual peak demand of each consumer, regardless of whether it occurs during system peak periods.[42]

Table 2

Typical Commercial Rate with a Demand Charge

Rate Element	Illustrative Rate	How Applied
Customer Charge	$10/mo	Independent of usage
Demand Charge	$10/kW	Customer's highest 1-hour usage per month
Energy Charge	$.10/kWh	All kWh

It is generally agreed that demand or capacity-related costs, to the extent they occur on a system, are primarily associated with the system peak demand, not the individual customer peak demand. Only very local components of the distribution system (service drop, line transformer) are sized to the individual customer load.

Because traditional demand charges are measured on the basis of the individual customer's peak, regardless of whether it coincides with the peaks on any portion of the system, this approach results in a mismatch between the system coincident peak costs used to set prices and the actual costs incurred at the time of the customer's non-coincident peak. While the revenue to be collected is represented by the system coincident peak costs, the billing units used to set the prices are the sum of all customers' individual non-coincident peaks. This results in a lower demand charge for everyone, but has the effect of requiring customers who are not contributing proportionately to the system peak to bear a greater share, while those who are contributing to the system peak bear a lesser share of

41 The alternative to using a renewable resource as the benchmark would be to include conventional resources plus the monetized cost of societal impacts; since this is unknowable, the prudent alternative is to use an emissions-free resource as the benchmark.

42 Individual peak demands measured in this manner are typically referred to as non-coincident peaks.

revenue responsibility than would occur if demand charges were based on usage during the system coincident peak.

A demand "ratchet" is a rate element that requires a customer to pay a demand charge in every month that is based on their highest usage during the year, often based on summer peak demand. These provide stable revenues to utilities, but discourage energy efficiency throughout the year, since a significant part of the cost of service is fixed and the savings from peak load reduction from energy efficiency are not realized until the ratchet period has been completed. This also has the effect of aggravating the mismatch between on-peak costs and on-peak usage, noted above.

Power Supply Costs

Power supply costs include the investment-related capital costs of power plants and transmission costs, fuel and purchased power costs, and generation and transmission operations and maintenance (O&M). In the past, many of these, such as capital costs and purchased power demand charges, were treated as demand-related costs, allocated to each customer class on a measure of demand (typically class contribution to system coincident peak, average demand, or a combination of the two). These may be reflected in individual customer demand charges, based on individual customer peak usage (not necessarily coincident to the system peak) for large-use (i.e., commercial and industrial) customers, or, preferably, in time-of-use (TOU) energy charges.

Fuel and purchased power costs, most of which were treated as energy-related costs, are typically allocated among the classes on a measure of total energy consumed (annual, seasonal, or time-varying). For electric utilities, as in other industries, capital costs, on the one hand, and short-run incremental unit costs (e.g., fuel and purchased power costs), on the other, are substitutes. A capital-intensive generating resource like wind, solar, or nuclear displaces fuel costs, typically gas or coal; a local resource like a combustion turbine displaces the need for transmission.

Likewise, a market mechanism that pays customers to reduce demand during high price periods or when the system is under stress displaces the need for generation, transmission, and distribution to meet short-term peaking requirements. In restructured and competitive wholesale power markets, however, the power supply costs discussed above in this section are nearly all recovered on a time-varying energy basis. A small portion may be recovered in capacity payments, but experience in the PJM and ISO-NE regions shows that, where allowed to compete, demand response potential quickly bids down the prices for short-duration capacity.

Principles for Rate Design in the Wake of Change

Good rate design should work in concert with the industry's clean technological innovations and institutional changes. Accomplishing this requires the application of well-established principles to inform the design of rates that promote economic efficiency, equity, and utility revenue recovery. This will be critical in a future characterized by significant customer-side resource investment and smart technology deployment. The advantages of a state that embraces these efficiency, equity, and utility revenue adequacy goals are significant, especially in maintaining a state's competitiveness and promoting customer choice and ingenuity. Unleashing the potential of new technologies will also require consideration of changing stakeholder interests as the power sector evolves.

Best practice rate design solutions should balance the goals of:

- Assuring recovery of prudently incurred utility costs;
- Maintaining grid reliability;
- Assuring fairness to all customer classes and sub-classes;
- Assisting the transition of the industry to a clean energy future;
- Setting economically efficient prices that are forward-looking and lead to the optimum allocation of utility and customer resources;
- Maximizing the value and effectiveness of new technologies as they become available and are deployed on, or alongside, the electric system; and
- Preventing anti-competitive or anti-innovation market structures or behavior.

Stakeholder Interests

Finding common ground on rate design among utilities, consumer advocates, environmental advocates, and others is not easy. The interests are different, the perspectives are different, and even the perceived public policy goals are viewed differently by different parties.

Utility Interests

Utilities tend to see costs associated with generating plant, transmission, distribution, and customer billing as "fixed costs" and generally seek a reliable method for assuring their recovery. Recently, a number of utilities have sought to recover these costs through fixed charges or demand charges, asserting that "fixed costs" should be recovered through "fixed charges." The use of high fixed charges is one avenue being pursued to provide revenue stability to the utility, independent of sales volumes and independent of whether the customer deploys energy efficiency or distributed generation.

Utilities seeking high fixed charges argue that the per-customer responsibility for distribution service is fully independent of sales volumes to the customer, because all customers must use the distribution network and should share equally in distribution system costs. In this view, when solar customers reduce their usage of grid-supplied power, their responsibility for distribution cost recovery is undiminished. They perceive that if solar customers do not pay these costs, then the burden falls either on other electric consumers (after a rate case or decoupling adjustment) or on utility shareholders.[43] From the perspective of other customers, this is no different than the earnings effect from customers who reduce their usage through conservation, energy efficiency, or departure from the system. On growing systems in the South and West, most of these reductions in cost recovery are offset by overall growth in the number of customers served by the utility.

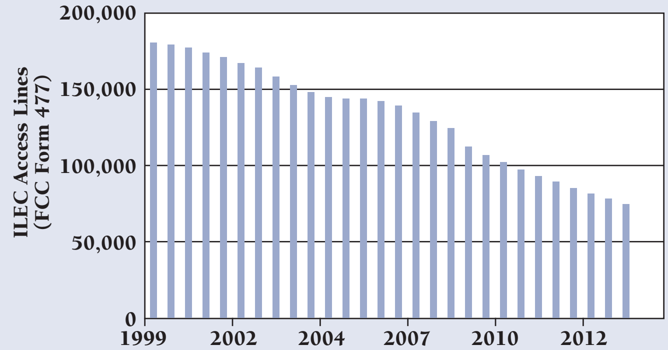
That said, no rate design can get around the basic constraint that the costs of service can only be allocated among existing customers and across their collective usage, unless the regulator finds that a portion of these costs should be disallowed from the revenue requirement. In low- or negative-growth states, this can create a schism between consumers pursuing efficiency and renewable energy sources and consumers who obtain all of their power from the grid. The issues surrounding the use of high fixed charges may have more to do with the adverse impact on low-use customers (who are often lower-income or live in urban areas or in apartments) and anti-competitive effects on competing generating resources (e.g., customer-owned DG), than recovery of costs by the utility.

Later on in this paper (see "Utility-Defensive Rate Design Principles"), as well as in Appendix D, we discuss why the use of high fixed charges may be a problematic strategy in the long run compared with alternatives. Both the telephone and cable television markets have imposed higher fixed charges. Both have seen significant customer and revenue attrition as customers have moved to competitive and volumetric alternatives. Similar results may be expected for electric utilities that employ this approach.

Consumer Interests

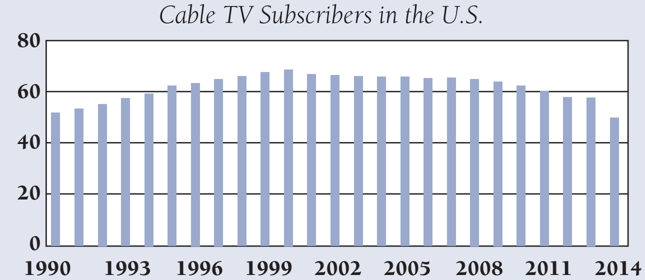
Consumers and their advocates come in many varieties. State consumer advocates may sometimes have different perspectives from low-income advocates. State consumer advocates are generally focused on minimizing the utility revenue requirement, and minimizing utility rate increases for all customers. They tend to favor a flat rate, and the plethora of bill riders utilized by some utilities is anathema to them.[45] Nonprofit consumer advocates mostly (but not

How Did High Fixed Charges Work Out for the Landline Phone Companies?[44]



How About Cable TV?

Cable TV Subscribers in the U.S.



43 A case can be made that utility shareholders are only affected during the period between the reduction in sales to solar customers and the implementation of new rates after the utility's next rate case or potentially through a decoupling mechanism, depending on how it is structured.

44 Data from Federal Communications Commission

45 Although, in some states, consumer bills look more like long-running scorecards for regulatory battles between the utility and ratepayer advocate, showing special charges for utility victories and special credits for ratepayer advocate victories. See, for example, a residential bill from any of the large utilities in California. As a result, the consumer is often left with a clouded understanding of the prices being charged for energy and a reduced ability to respond appropriately.

always) have a pro-environment perspective. Low-income advocates may perceive their clients to be "have-nots" in the drive for distributed energy and smart technology who are adversely impacted when households with more disposable income choose to invest in solar energy or smart appliances. Their focus is on affordability for the most vulnerable populations. Occasionally, interest groups representing large-use residential consumers form, and they typically have a very different perspective than other consumer advocates.

Rate design that favors energy efficiency and renewable energy helps to minimize the overall utility revenue requirement, but may also result in higher per-kWh prices as distribution costs are spread across lower sales levels. Most consumer advocates will favor rate design with low fixed charges, to ensure universal service and protect low-use customers.

Low-income advocates have generally also favored rate designs with low fixed charges and inclining blocks, recognizing that the majority of low-income consumers will benefit. They raise skepticism about default or mandatory TOU pricing,[46] because some low-income families have little ability to shift consumption. However, they are also concerned about high-use low-income households. Part of the challenge is that the construction of these households and their appliances is generally less efficient. That has been and can continue to be addressed through energy-efficiency programs and in some states through discounted rates for low-income consumers. Part of the problem is that reaching all low-income households through energy efficiency and weatherization will take years to accomplish given the funding available and the large number of homes in need.

Further, the needs of large families, often multi-generational, sharing dwellings due to the high cost of housing are more challenging to address within rate design, except by designing rates to favor high-use consumers or by designating a customized customer baseline within an inclining block rate design. California does this for electric and gas rates by defining housing types and climate zones and setting differential baselines; some water utilities allow customers with large families or medical needs to apply for a higher baseline allowance, and this approach could be applied to electricity.[47]

Large industrial energy user advocates often prefer rate designs with higher fixed charges and low volumetric energy rates, because this minimizes their bills given their high-volume 24/7 usage. Many often seek "economic development" discounts. They engage in DR where profitable and seek to opt out of utility energy efficiency programs. This group also tends to voice concerns about the costs of RPS.

Solar Interests

The solar industry now employs more people than the coal or nuclear industry in the United States and is not a trivial interest.[48] Falling costs for PV have resulted in a surge of customer-sited PV systems. This industry is growing and regulators will be forced to grapple with the impact of solar installations on the utilities they regulate and the customers they are charged with protecting. With respect to rate design, regulators should assure that solar technology is fairly treated, while addressing the concerns of utilities and other customers.

The customer-sited solar industry has an interest in ensuring that their access to customers is unrestricted, and that those customers get the maximum economic value from an investment in solar energy. Industry representatives see pricing that recovers production or distribution costs in fixed charges as anti-competitive behavior and an unacceptable deployment of monopoly pricing power that utility regulation was created to prevent. This group favors traditional net metering, low customer charges, and inclining block rate designs that align the end block of rates with the long-run societal cost of power (including environmental, risk, and other costs). They also favor feed-in tariffs (FITs), RPS with solar carve-outs, and value of solar tariffs (VOSTs). Current research into the actual value

46 "Default" TOU pricing refers to the introduction of TOU rates for a customer class and automatically putting all customers in the class on the new rate, but allowing them to opt out. This is as opposed to offering the rate on an opt-in basis, which requires action on the part of the customer to begin using TOU rates.

47 Brown, J.M. (2014). Hundreds request more water amid Santa Cruz rationing. *Santa Cruz Sentinel*, May 17, 2014. Available at: http://www.santacruzsentinel.com/general-news/20140517/hundreds-request-more-water-amid-santa-cruz-rationing

48 Korosek, K. (2015). In U.S, there are twice as many solar workers as coal miners. *Fortune*, January 16, 2015. Available at: http://fortune.com/2015/01/16/solar-jobs-report-2014/

of solar to customers who deploy it, as well as the value to other customers, tends to support the conclusion that the value of solar equals or exceeds the "payment" to customers realized through NEM.[49]

However, solar vendors that focus on the utility-scale solar installation market may see things a little differently. They may benefit from actions that discourage rooftop solar installation in favor of central station solar facilities. To the extent that the grid has limited flexibility to accept variable power, their interests are harmed when penetration of rooftop solar begins to affect the operation of the grid. As long as the system has constraints on the overall level of intermittent resources, distributed solar and central station solar interests will potentially be in competition with one another.

Unregulated Power Plant Owner Interests

Independent power plant (IPP) owners with coal or nuclear resources are threatened by the deployment of competing generation resources, whether they are central-station renewables or distributed renewables. The presence of these resources depresses power prices in the middle of the day[50] and, depending on whether theirs is the marginal generating unit at the time, may displace the utility's own generation. This tends to make the market favor flexible resources, such as gas turbines, that can ramp up sharply in the afternoon when the solar day ends. IPPs also have a negative view of energy efficiency and DR, as these resources tend to reduce prices in both the wholesale energy and capacity markets.[51] Conversely, unregulated owners of flexible generation may welcome the deployment of variable renewable energy resources, especially if the flexibility of their plants is valued and monetized.

Societal Interests

Societal interests encompass the interests of all of the market participants, including those identified above, plus all non-market participants and interests. Society as a whole values overall economic efficiency. Societal interests also include all environmental impacts of the electric system, including carbon dioxide and criteria pollution emissions, and also other impacts such as fuel cost risk, fuel supply risk, the value of a diversified portfolio of resources, the economic development value of stimulating new resource development, efficient utilization of natural and societal resources, health impacts, health costs, and other factors.

The regulator accepting the charge of "regulating in the public interest" considers all of these values. They may in some instances be legally constrained from *monetizing* all of these in resource procurement decisions, but even then, the presence of societal interests should be identified and recognized so that legislatures and courts are aware of the constraints they have imposed and the increased costs that are incurred or benefits that are not realized when these values are not monetized.

Resource Value Characteristics

A good illustration of the different values of system resources may be found in a 2012 decision of the Vermont Public Service Board.

Figure 5 shows the multitude of measurable values of energy efficiency. These are separated into those that are typically reflected in the utility revenue requirement and those that are not, while highlighting those that vary in the short run: energy, line losses, and avoided reserves. Relatively few regulators consider risk (fuel supply risk and fuel cost risk), or difficult-to-quantify non-energy benefits (DTQNEB) in the conservation program valuation process, and most do not consider avoided water, sewer, natural gas, propane, or heating oil savings. All of these are important elements of the total value stream that electricity efficiency investments help procure.

In the context of this graphic, consumer interests reflected in utility tariff rates are in the lower portion of the graph. Utility interests, in the short run, will focus only on those items that vary in the short run; owners of unregulated generating units may share that short-run interest. Societal interests include the entire range. Rooftop

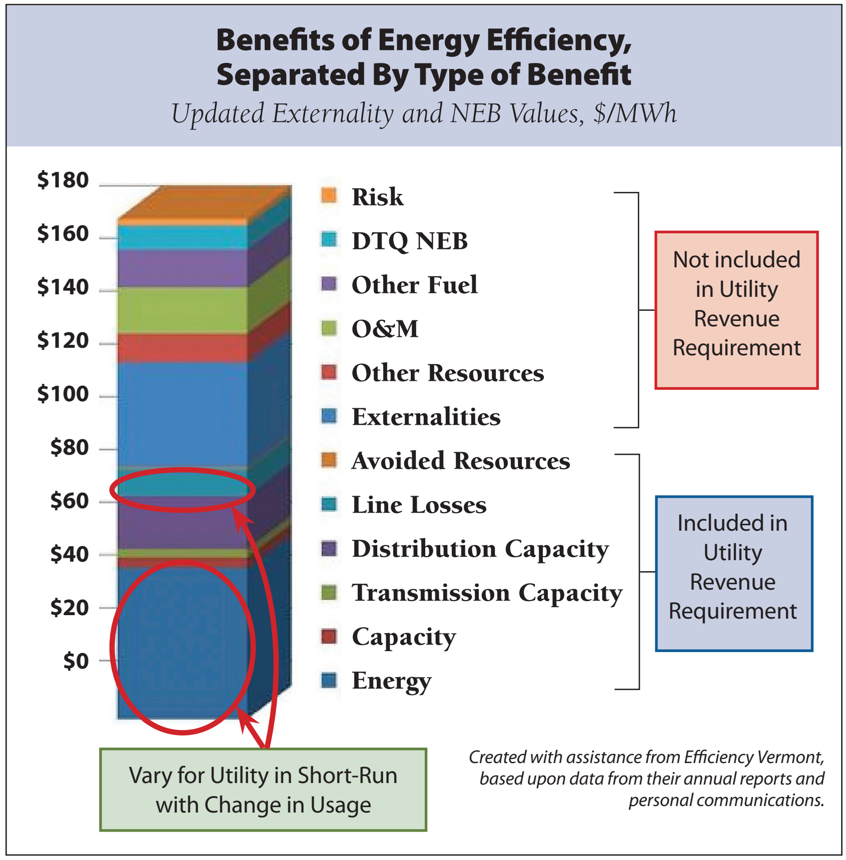
49 See, for example, Minnesota's VOST methodology at http://mn.gov/commerce/energy/businesses/energy-leg-initiatives/value-of-solar-tariff-methodology%20.jsp or Maine's at http://www.synapse-energy.com/project/value-distributed-solar-maine

50 Power prices from competitive generation can also be affected at night. For example, high winds blowing in the middle of the night can lead to negative prices.

51 Litvak, A. (2014). FirstEnergy says demand response putting power plants out of business. *Pittsburgh Post-Gazette*, November 25, 2014. Available at: http://powersource.post-gazette.com/powersource/policy-powersource/2014/11/25/FirstEnergy-says-demand-response-putting-powerplants-out-of-business/stories/201411250013

solar installers will want to embrace the entire range, while central-station solar developers will want to consider the entire group of costs at the top of the graphic —those that are not included in the utility revenue requirement as values of their product. However, they may not consider distribution costs for the utility, as their product does not displace these.

Figure 5



Principles Specific to Customer-Sited Solar Rate Design

Rate design for solar customers should adhere to the following refinements within the three basic principles of rate design discussed previously:

- **Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.** Only customer-specific costs should be applied to the bill for the privilege of connecting to the grid and accessing grid services.
  - The only truly customer-specific costs, which vary with the number of customers on a typical urban/suburban electric grid, are service drops, meters, and billing services. The grid itself does not change with the number of customers connected to it.
  - If a customer is already connected to the grid and then invests in a PV system, then a one-time cost-based fee may be appropriate to process the net metering and interconnection agreement and to inspect the installation if required. The rationale for this principle is discussed at length in Appendix D.

- **Principle 2: Customers should pay for grid services and power supply in proportion to how much they use these services, how much power they consume, and when they consume this power.** Nearly all utility services should be priced volumetrically, but may vary by time of day, season of year, and by voltage level (customers only pay for the portions of the distribution system that serves them).
  - **The cost for use of the distribution grid should be charged in relation to customer purchases of energy and not for customer-generated energy delivered to the grid.** Customer-owned generation should be treated in the same manner as other generators who supply energy to the grid. Accepted market practice is to charge consuming customers for use of the distribution system, rather than generators. High-voltage transmission rates are sometimes borne by generators seeking to sell their product to a specific utility at a specific point of delivery.
  - **Time-varying rates are appropriate in both directions.** Utility time-differentiated rate designs should treat DG customers in a symmetrical manner. If DG produces "valuable daytime power," the customers installing DG should reap that benefit through higher remuneration and likewise, if DG customers require "valuable ramping period" power, DG customers should pay higher bills for that at the same rate charged to other users at that time. Smart meters with bidirectional capability enable the utility to offer time-differentiated TOU and critical peak pricing (CPP) rates to their customer base. DG and non-DG customers who subscribe to those types of rates will be paying a more cost-based rate and therefore there is less chance for inappropriate apportionment among customers. It may also be appropriate to require

that DG customers be on a TOU rate so that what they pay for energy and what they receive in compensation more accurately reflects the utility's true costs.

- The presence of high levels of solar on a utility system may dramatically suppress the on-peak period prices that affect most utility systems during afternoon hours. If the time-varying pricing is changed to reflect this, the net effect is that non-solar customers receive lower afternoon prices as a result of solar customer investments, while solar customers receive less in the form of avoided payments to the utility. When pricing solar on a "value" basis, some of the benefits from the price reductions should continue to flow to the solar producers in recognition of the fact that it is their continued presence that creates this value for all customers.
- **The PV customer should pay for power supply and distribution service at non-discriminatory rates for all power received from the grid.** When PV customers are drawing power from the grid they should pay for power supply and distribution service, and any other generation costs, at the same price as non-PV customers. Until TOU rates are universal, a good temporary approach would be to place all solar customers on a TOU rate that has the same fixed charges applied to non-TOU customers. This would ensure that solar customers pay the full costs of power supply and grid services they receive.
- The only component of the distribution system that is sized to the individual demands of the individual customer is the final line transformer. Although these need to be sized to the maximum level of usage (in either direction) for a DG customer, this is a very small component of the total distribution system cost. DG customers seldom require more capacity to feed power to the system than they require for their night-time consumption.
- **Recovery of distribution costs as customer usage profiles change.** At the distribution level, the overwhelming majority of utility regulators have allowed distribution costs no longer being paid by consumers who generate power on-site to be recovered from remaining (and new) sales. As a practical matter, recovery of these costs across the reduced usage caused by distributed generation is no different than the recovery of newly installed distribution facilities that temporarily represent excess capacity or reductions in revenues associated with customers who reduce usage through energy efficiency, conservation, or by terminating service altogether. In all these cases, traditional cost allocation methodologies, based as they are on customer usage at any given point in time, reflect the dynamic nature of the electric system and of its utilization by customers and have always been considered "fair" at any such point in time.

Some participants in the regulatory process have portrayed PV as unfairly shifting costs to other customers or of utilizing the system in some way without paying for it. This is a misapplication of rate design and cost recovery principles and practice, which have never charged generators for use of the distribution system, as well as accepted cost allocation methods that are themselves dynamic in nature. It also mischaracterizes how and when DG customers use the distribution system, incorrectly equating injection of energy into the system with deliveries taken from the system. In truth, at any given point in time, only those customers who are taking energy from the distribution system are using that system. When injecting energy into the system, DG customers are not using the distribution system any more than a remote central-station generator is using the system — that is, not at all. In fact, when energy is injected into the distribution system at the customer's location, energy losses in that system actually go down and the net effect is a negative cost — i.e., a benefit — from the presence of the DG.

- **Principle 3: Customers that supply power to the grid should be fairly compensated for the full value of the power they supply.** Prices paid, or amounts credited for customer generation, must consider avoided production, transmission, distribution, environmental benefits, losses, reserves, fuel cost and fuel supply risk, and other avoided costs that their power supply may provide to the public. For some utilities, this will be more than the retail rate, and for others, it will be less.
  - **DG customers should be free from discrimination. Most state statutes have provisions prohibiting discrimination among and within classifications of customers.** DG customers should be accorded the same protection. Fixed or other non-economically based charges should not be imposed on DG customers. Any cost

imposed on a DG customer should be based on a real cost to the utility system resulting from the DG, net of cost savings resulting from the DG. Just as customers who install efficient LED lighting in their homes to reduce their bills are not charged individually for the energy they do not consume, neither should solar customers who displace their purchases with solar generation.

- **NEM is a reasonable proxy for the value of solar in the absence of better information.** Solar power delivered to the grid at the distribution level is a superior product with higher value than generic "grid power" due to locational and environmental characteristics. These benefits must be considered in determining the proper fair compensation to the PV customer supplying power to the grid. In the absence of a VOST or of data on the various values of solar, it is appropriate to continue the use of NEM as a proxy for those values. It is unlikely that this will overcompensate DG customers and likely that it will still send sufficient price signals to the customer to make economic choices about whether to install DG or not.

Current and Emerging Rate Design Proposals

Many alternatives have been suggested for future rate design applications from sources as divergent as the Edison Electric Institute and the Rocky Mountain Institute. Most recent rate design studies emphasize the need for time-varying pricing and for some form of demand-response pricing. At the same time, stakeholders currently face a legacy system of non-TOU rates that are either flat across all usage levels or are designed with increasing or decreasing prices for increasing amounts of consumption ("inclining block rates" and "declining block rates" respectively). They may also include demand charges in addition to energy charges (typically for commercial and industrial users and in rare instances for high-use residential customers), although various types of TOU rates have been used.

Traditional Rate Designs

Time-Differentiated Pricing

It is hard to envision an electric system future without greater utilization of time-differentiated pricing. Because the underlying costs of providing electricity vary hourly and seasonally, it is impossible for the customer to see an appropriate price signal without that signal also varying over time. As smart technologies take hold, the connection between customer usage patterns and underlying costs will become apparent. As this happens, it is inevitable that time-differentiated pricing will become more widespread. A number of time-differentiated rates have already been utilized by utilities and are outlined below. Their importance as part of a best practices approach to rate design is discussed in the following pages (see "Best-Practice Rate Design Solutions").

Time-of-Use Rates

TOU rates have been in use for some time in the United States. These rates typically define a multi-hour time of the day as "on-peak" period, during which prices are higher than during "off-peak" hours. In most cases, on-peak periods are limited to weekdays. Some TOU rates also include a "shoulder" rate for usage occurring between on-peak and off-peak periods. In some cases, they are limited to summer or winter periods and are not applied during spring and fall periods when overall loads on the system are not as high. TOU rates require the use of a more advanced meter (i.e., an "interval" meter that can report usage for specific periods of time) than is typical for non-TOU customers. Today's advanced smart meters can also provide this function at yet a more temporally granular level.

TOU rates are common, and often required, for commercial and industrial customers of all sizes. For residential customers, they are in most cases optional if they are offered at all.

TOU rates are an improvement over flat or inclining block rates because they offer some correlation between the temporally changing costs of providing energy and the customer's actual consumption of energy. However, they are usually not dynamic in the sense of capturing the real underlying changes of costs from hour to hour, day to day, or season to season. If the high-cost hours cover too much of the day, however, customers may not be able to adjust their usage to adapt. Concentrating peak-related charges into as few hours as possible produces a better customer response and actually tracks closer to underlying increased costs, which are, themselves, concentrated into relatively few hours of the day and year.

Critical Peak Pricing and Peak-Time Rebate

Critical peak pricing (CPP) and its common variant peak-time rebate (PTR) are a more dynamic variation on the TOU concept. Under CPP, prices during specific "critical peak periods" are set at much higher prices.

Typically, under CPP, the customer agrees to pay the high price during a short (e.g., three-hour) period on a few declared "critical peak days" of the year. There is usually a maximum number of days (and total hours) that can be declared as critical — often three or four hours per day, ten to 12 days per year, or less than 1 percent of the hours of the year. Those days may also be limited to the on-peak season, usually summer or winter, depending on when the utility experiences its overall system peak. The customer is given some advance notice of critical peak days, usually a day in advance. CPP is designed to produce a response — to get customers to reduce loads during critical peak periods. The CPP has been largely successful. To date, CPP rates have been voluntary opt-in rate forms, but evidence supports setting these as default rates for large groups of consumers.

Table 3

CPP and PTR Rate Illustrations

Critical Peak Pricing	Peak-Time Rebates
CPP uses pricing to set the consumer price for consumption during critical peak events.	PRT uses customer rewards (discounts) for curtailing usage during critical peak events.
The baseline rate is lower, and customer is charges a very high price for usage in these events.	The baseline rate is higher than for CPP, but the customer receives a credit for reducing usage in these events.
Illustrative Rate Customer Charge: $5.00/mo	**Illustrative Rate Customer Charge: $5.00/mo**
Off-Peak Usage: $.08/kWh	Off-Peak Usage: $.09/kWh
On-Peak Usage: $.15/kWh	On-Peak Usage: $.17/kWh
Critical Usage: $.75/kWh	Critical Usage: -$.75/kWh

A closely related variant to CPP is the PTR. Under the PTR concept, rather than charging customers an elevated critical peak price, customers are given a large credit on their bills if they can reduce usage during a peak-time event. This requires the identification and quantification of what the customer's usage would have been (i.e., a baseline) in the absence of the usage reduction. PTR is distinguishable from a CPP in that it is a voluntary program. Failure to participate does not result in any penalty, but the customer pays a slightly higher rate to which credits are applied.[55] Table 3 compares the two approaches.

Just as in the case of TOU, CPP and PTR both require the use of an interval meter or a smart meter.

Real-Time Pricing

Real-time pricing (RTP) charges the customer the actual prices being set in wholesale markets (for utilities that are not vertically integrated) or short-run marginal generation costs (for vertically integrated utilities) as they vary hour by hour.[56] Prior to the introduction of smart technologies, only the largest customers would typically be on RTP, as it usually requires either a trained, often-dedicated, employee or a third-party service provider to constantly monitor prices and manage load in order for the customer to take advantage of this type of pricing. As newer smart technologies take hold, some form of RTP may expand to other customers who have smart appliances that can monitor prices automatically, respond accordingly, and monetize the benefits.

Feed-In Tariffs and Value of Solar Tariffs

Several jurisdictions have adopted special pricing for compensation of solar customers for the power supplied to the grid by these systems.

55 A recent US DOE study reports that average peak demand reductions for customers taking service on critical peak pricing (CPP) rates were almost twice the size (21 percent) than they were for customers participating in critical peak rebate (CPR) programs (11 percent). However, when automated controls were provided, peak demand reductions were about the same (30 percent for CPP and 29 percent for CPR). See: US DOE. (2015). *Interim Report on Customer Acceptance Retention, and Response to Time-Based Rates from the Consumer Behavior Studies.* Smart Grid Investment Grant Program. Available at: http://energy.gov/oe/downloads/interim-report-customer-acceptance-retention-and-response-time-based-rates-consumer

56 New Jersey has a pure RTP for their largest customers (i.e., hourly price based on integrated average of the past hour zonal LMP in PJM's spot market). This is different than other applications of RTP, which are predicated on system lambda or LMP out of unit commitment algorithms that are run a day-ahead.

Table 4

Feed-In-Tariff for Gainesville, Florida

Category	20-year Fixed Rate	Capacity (DC peak kilowatts)	Mounting Configuration
Class 1	$0.21/kWh	10 kW or less 10 kW or less	Rooftop or over pavement Ground mount
Class 2**	$0.18/kWh	>10 kw to 300 kW >10 kW to 25 kW	Rooftop or over pavement Ground mount
Class 3***	$0.15/kWh	>25 kW to 1,000 kW	Ground mount

* *For projects approved and installed in 2013.*
** *Minimum capacity requirements do not apply for Class 2 projects if a Class 1 system is already installed on the parcel.*
*** *GRU did not accept Class 3 projects in 2013.*

Source: Gainesville Regional Utility

Value of Solar Tariff

A VOST is fundamentally different from a FIT, compensating the solar provider on the basis of the value provided, not the cost incurred. Studies conducted by the city of Austin, and the states of Minnesota and Maine, showed that a VOST will generally provide equal or greater compensation to the solar producer than simple net metering, reflecting the combined high value of the energy and non-energy benefits provided by solar.

The VOST concept was pioneered by the municipal utility in Austin, Texas, which established a VOST as a way to compensate solar producers for energy that was more valuable than the average of utility resources that were reflected in rates. Simple net energy metering would have given the solar customers too little compensation given the value of their power. Since that time, Austin has raised its retail prices, and reduced the VOST. Figure 6 compares the rate blocks of the current Austin Energy residential tariff to the VOST in effect today. Small-use customers receive more benefit from the VOST than they would from a net energy metering rate.

As discussed later in this report, more recent VOST studies have shown significantly higher values than Austin has adopted. These generally consider a broader range of costs than the narrower group included in the Austin VOST.

For utilities where only a small percentage of consumers have installed solar systems, a simple net energy metering option will generally be easier to measure, more acceptable to consumers, and simpler to administer, and will produce fewer significant impacts on grid-dependent customers. If solar penetration is high, the additional costs to install smart meters capable of bidirectional measurement may be justified, and time-differentiated pricing for power flows in each direction may be appropriate. The customer pays for power used on a TOU basis, and is credited (either the retail TOU rate or a different time-differentiated VOS rate) for power fed to the utility.

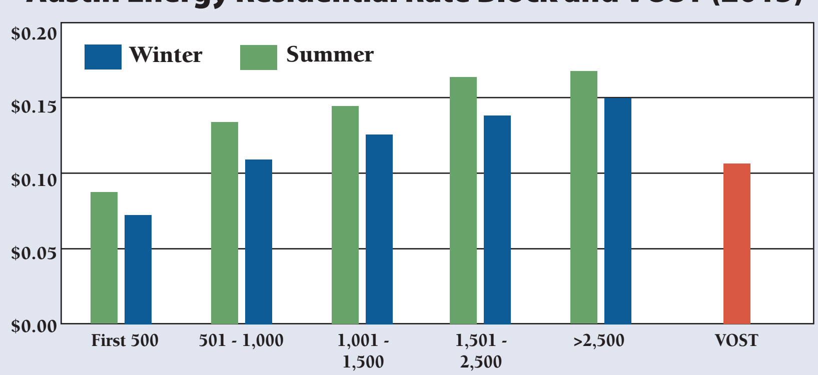
Feed-In Tariffs

Originating in Europe, feed-in tariffs (FITs) paid a premium price for renewable energy, generally based on the cost of the resources, not the value of the output. The payments for solar were typically higher than for wind, and the payments for power from small systems were greater than for larger systems. FITs were generally designed to be an infant-industry incentive, providing a large and stable payment to support the decision to invest, and often were more generous in the early years to reward early adoption. Often, the FIT prices were set for the life of the resource or some extended period of time.

An example is the FIT adopted by the municipal utility for Gainesville, Florida, which applied to facilities built through 2013 and provided these customers with long-term contracts for the purchase of the output from the solar DG, as shown in Table 4.

Figure 6

Austin Energy Residential Rate Block and VOST (2015)



Source: Austin Energy

Utility-Defensive Rate Design Proposals

Recent growth in DG has been very rapid. Installed solar capacity in the United States increased 30 percent in 2014 and residential installations surpassed 1 gigawatt.[57] The relative success of DG has raised concerns in electric utility boardrooms and has caught the attention of the Edison Electric Institute.[58] This success has led to the proposal and implementation of rate designs that undermine the economics for existing DG customers and present a formidable barrier for customers contemplating investments in DG resources.[59] These proposals may impair the value that DG brings to the grid and to society as a whole. Renewable solar and wind businesses that have relied on federal tax credits, state RPS directives, and NEM have a lot at stake and are reacting to preserve their business model. A primary goal of these policies was to help transform the market in order to allow volume sales to reduce the unit costs and, as has been noted above, prices have declined significantly over the past decade. The policies have been successful, and this success presents new challenges to utility regulation.

Some utilities have proposed rate designs that are intended to assure recovery of embedded system costs from solar customers. As stated in a recent article, "The industry and its fossil-fuel supporters are waging a determined campaign to stop a home-solar insurgency that is rattling the boardrooms of the country's government-regulated electric monopolies."[60] Meanwhile, states such as New York are looking to reform their utility business models to be more in line with customer preferences and choices.[61] The uncertainty created by some of these proposals could cause a disruption in clean energy investment. If implemented, these proposals may drastically curtail deployment of customer-sited DG.

High Fixed Charge Rates

The expansion of energy-efficiency programs and customer generation, coupled with a weak economy, increasingly stringent building and appliance codes and standards, and fuel switching has led to flat or declining electricity sales[62] in some parts of the United States[63] and a serious challenge to the traditional electric utility business model that ties profitability to electricity throughput.[64] Utilities have sought to shore up their revenues by imposing minimum fees or new fees to replace declining sales.

57 Doom, J. (2015). *U.S. Solar Jumps 30% as Residential Installs Exceed 1 Gigawatt.* Bloomberg Business, March 10, 2015. Available at: http://www.bloomberg.com/news/articles/2015-03-10/u-s-solar-jumps-30-as-residential-installs-exceed-1-gigawatt-i738dw27. "GTM Research expects solar demand this year will grow 31 percent to about 8.1 gigawatts."

58 Kind, P. (2013). *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business.* EEI, January 2013. Available at: http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf

59 Tong and Wellinghoff, 2015.

60 Warrick, J. (2015). Utilities wage campaign against rooftop solar. *Washington Post,* March 7, 2015. Available at: http://www.washingtonpost.com/national/health-science/utilities-sensing-threat-put-squeeze-on-booming-solar-roof-industry/2015/03/07/2d916f88-c1c9-11e4-ad5c-3b8ce89f1b89_story.html

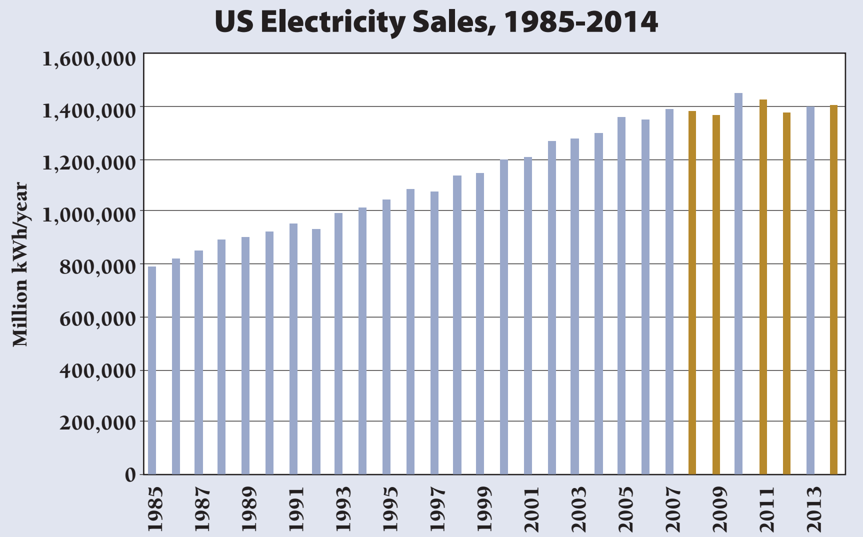
61 See New York Public Service Commission, "Reforming the Energy Vision," at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2.

62 US Energy Information Administration. (2015, April). Electric Power Monthly. Available at: http://www.eia.gov/electricity/monthly/update/archive/april2015/

63 Faruqui, A. (2012). *The Future of Demand Growth: How Five Forces Are Creating a New Normal.* Presentation before the Goldman Sachs 11th Annual Power and Utility Conference, August 14, 2012. Available at: http://www.brattle.com/system/publications/pdfs/000/004/431/original/The_Future_of_Demand_Growth_Faruqui_Aug_14_2012_Goldman_Sachs.pdf?1378772105. One counter to this perspective states that the future of the electric sector is decarbonized transport and industry and therefore electricity sales will grow significantly over the next 40 years.

64 See Kind, 2013, and Craver, T. (2013). Raising Our Game: Distributed energy resources present opportunities and challenges for the electric utility industry. *Electric Perspectives,* EEI, September/October 2013. Available at: http://www.edison.com/content/dam/eix/documents/our-perspective/2013-09-01-RAISEGAME.pdf

Figure 7



Source: US EIA

that approximately 1.5 percent of consumption would have an incentive to increase usage to the level of the minimum bill, and over 98 percent of consumption would have a higher incentive to constrain usage.

Straight Fixed/Variable Rates

Utilities in some parts of the United States are seeking changes to rate design that sharply increase monthly fixed charges, with offsetting reductions to the per-unit price for electricity. High fixed charges as part of a straight fixed variable (SFV) design can stabilize utility revenues in the near term and are easy to administer. This approach however, deviates from long-established rate design principles holding that only customer-specific costs — those that actually change with the number of customers served — properly belong in fixed monthly fees. It also deviates from accepted economic theory of pricing on the basis of long-run marginal costs. The effect of this type of rate design is to sharply increase bills for all low-use customers — which includes most apartment dwellers, urban consumers, highly efficient homes, and customers with DG systems installed — while benefitting larger homes and suburban and rural customers.

A common objection to this kind of rate is that it discourages conservation and DG by decreasing customer savings and increasing paybacks in customer investments and that it results in bill increases for low-volume (sometimes low-income) customers while decreasing bills for large-volume (often wealthier) customers.

Because they lower the energy rate component of the

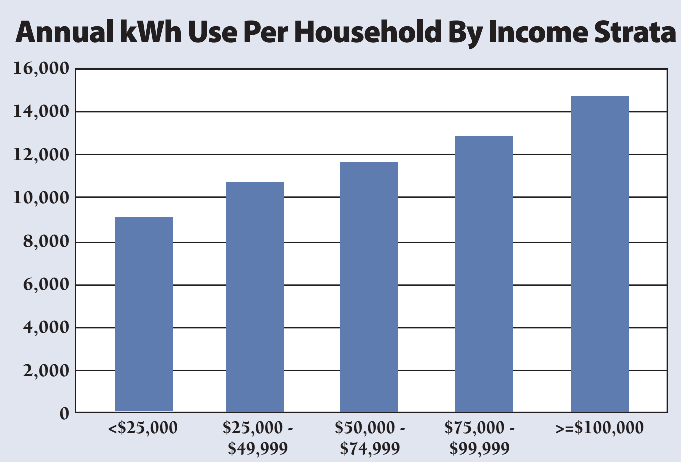
Minimum Bills

A minimum bill charges the customer a minimum fixed charge, which entitles the customer to a minimum amount of energy. For example, a residential minimum bill might charge $20 as a minimum charge, which entitles the customer to receive its first 100 kWh energy included in the price. The customer charge is usually included in the minimum bill charge. Because some customers may have total usage below the minimum energy threshold, prices for energy above the minimum will be reduced slightly to offset the additional revenue collected from those customers.

Minimum bills are not typically considered good rate design, because they have an effective "zero price" for very small levels of usage. They are better than Straight Fixed/Variable rates (discussed next), which can impose up to $50 or more as a fixed charge and impose sharply lower per-unit prices. To the extent energy efficiency, conservation, and customer-sited DG would reduce consumption below the minimum threshold, minimum bills have the effect of reducing their value. Customers considering any of these options would tend to reduce the magnitude of their effort as usage falls into the minimum-bill range because no further savings could be achieved.

The key is to set the minimum bill at a level that guarantees the utility a certain level of revenue it can count on, while not penalizing the vast majority of customers. Those most likely to be harmed with a minimum bill include seasonal households or households that are energy efficient and rely heavily on DG as their major source of energy. At the $20 per month minimum bill hypothetical, it is estimated

Figure 8



Source: John Howat, National Consumer Law Center, 2014 customer's tariff, SFV rates discourage conservation and DG by decreasing customer savings associated with reduced consumption, thereby increasing payback periods in customer investments. SFV rates adversely impact those who have already invested efficiency and DG and may dissuade those who are considering such investments from deploying energy efficiency and DG.

Later in this paper, as well as in Appendix D, we discuss how the future is better served by reflecting costs that are not customer-specific — including nearly all distribution system costs — in usage-based (preferably time-varying) rates.

Distribution System Cost Surcharges

Some states, such as New Mexico, are considering imposing new fees on DG customers that utilities argue reflect their use of the grid. Arizona and Wisconsin have already imposed new fees on DG customers even though there may be no demonstrated additional costs being incurred by the utility as a result of DG output.[65] These new fee-based rate designs can adversely impact customers who have made investments predicated upon the stability of a historic rate design, as well as dissuade other customers from deploying DG. In some states surcharges applicable only to new solar customers are being considered. How these provisions are applied makes a difference in the impact they will have on new and existing customers. If there is a grandfathering provision for existing solar installations, they will discourage new solar installations, but not penalize customers who made investments based on expected savings.

On the other hand, commissions in Idaho, Louisiana, and Utah have rejected fixed charges on solar customers[66] while California has statutorily limited fixed charges to no more than $10 per month for all residential consumers, including any demand or other unavoidable charges.

Exit Fees

Exit fees are charges imposed on consumers who cease taking utility service. In general, these are applied only to consumers departing the system on short notice, and for whom the utility has made significant investments to provide service. This may be customer-specific distribution system investments, or may be investments in power supply intended to provide long-term service.

As a general rule, exit fees are inappropriate rate design measures. The risk of customer loss is an ordinary business risk, for which the utility rate of return is the compensation. In addition, overall growth in customers and customer usage may more than offset the losses from defecting customers, enabling utilities to redeploy resources freed up by conservation and DG to serve new customers or increased use by other existing customers.

Where specific costs are attributable to specific customers (for example, building a substation to serve an industrial facility), it may be appropriate to impose a charge based on the unamortized investment if the customer did not pay the costs of the facilities expansion as a connection charge at the time service was initiated. However, these costs are typically addressed in special contracts between the utility and the customer and not through a general exit fee tariff.

Best-Practice Rate Design Solutions

Overview: Rate Design That Meets the Needs of Utilities and Consumers

Figure 9 gives an overview of the appropriate rate designs for all customer classes for both default and optional services.[67]

65 In Wisconsin, the commission did not examine utility costs for DG customers, but instead determined that a fixed charge "more appropriately aligned costs." Likewise, the Arizona Corporation Commission granted an interim fixed charge increase for DG customers until the utility's next rate case without examining specific costs, rationalizing that such a move was necessary to address the "cost-shift" from DG customers to non-DG customers. See WI PSC. (2014, December). Final Decision. Docket No. 5-UR-107. Available at: http://psc.wi.gov/apps40/dockets/default.aspx; and AZCC. (2013, December 3). Final Decision. Docket No. E-01345A-33-0248. Available at: http://images.edocket.azcc.gov/docketpdf/0000149849.pdf

66 Tracy, R. (2013, July 8). Utilities Dealt Blow Over Solar-Power Systems. *Wall Street Journal*. Available at: http://www.wsj.com/articles/SB100014241278873245074045785941222250075566; and Trabish, H. (2014). Utah regulators turn down Rocky Mountain Power's bid for solar bill charge. September 3, 2014. Available at: http://www.utilitydive.com/news/utah-regulators-turn-down-rocky-mountain-powers-bid-for-solar-bill-charge/304455/

67 This is an update of a matrix developed in 2003 for the New England Demand Response Initiative, reflecting changing costs of smart grid capabilities and increased value of time-differentiation due to the high levels of variable renewable generation available today. See http://www.raponline.org/document/download/id/687.

Figure 9

Rate Design Options by Customer Class

	Typical Pre-AMI Rate Design	Inclining Block Rate	TOU Rate Fixed Time Period	TOU plus Critical Peak Pricing	Baseline-Referenced Real Time Pricing	Market Indexed Real Time Pricing
Residential	Flat Energy Charge	Default (if kwh-only metering in place)	Default (if TOU meters or AMI in place)	Optional if AMI in place	Pilot	Not Available
Small Commercial 0-20 kw Demand	Flat Energy Charge	Not Available	Default (if TOU meters in place)	Optional if AMI in place	Pilot	Not Available
Medium General Service 20-250 kw	Demand Charge --- Flat Energy Charge	Not Available	Default (until AMI installed)	Default (after AMI installed)	Optional	Not Available
Large General Service 250-2,000 kw	Demand Charge --- Flat Energy Charge	Not Available	Not Available	Default	Optional	Optional
Extra Large General Service >2000 kw	Demand Charge --- Flat Energy Charge	Not Available	Not Available	Not Available	Customer Must Choose Between These Two Options	

Source: Adapted from RAP research for New England Demand Response Initiative (NEDRI), 2002

Table 5

Illustrative Residential Rate Design

Rate Element	Based On The Cost Of	Illustrative Rate
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + transmission and distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

For residential consumers, the general rate design reflected in Table 5 will serve the needs of both utilities and consumers, providing incentives for efficiency, compensation for services received, and a pathway to a future that is less dependent on fossil generation. Differences will be appropriate for very low-cost utilities and very high-cost utilities. The issue of whether CPP or PTR is most appropriate to reflect needle-peak costs is discussed below (see "Time-Sensitive Pricing").

In the simplest of terms, this rate design recovers customer-specific costs, such as billing and collection in a fixed monthly charge, and combines power supply and distribution costs into a TOU rate framework. This enables fair recovery of costs from small and large customers, and from customers whose peak demands may occur at different times from one another, and at different times from the system peak. It also provides reasonable compensation to DG customers who supply power to the grid at certain times, and receive power from the grid at other times.

General Rate Design Structure

Demand Charges

Demand charges are usually based on the customer's metered peak usage over a short period of time (e.g., 15 minutes or an hour), regardless of whether that usage coincides with the generation peak, transmission system peak, distribution system peak, or the customer's circuit peak. In addition, demand charges are often "ratcheted," which means that the customer pays a monthly demand charge based on the maximum metered peak over a longer than one-month period — usually a year.

Demand charges were implemented for commercial and industrial customers in an era where sophisticated TOU metering was prohibitively expensive. Today, with smart meters and AMI, these costs are trivial.

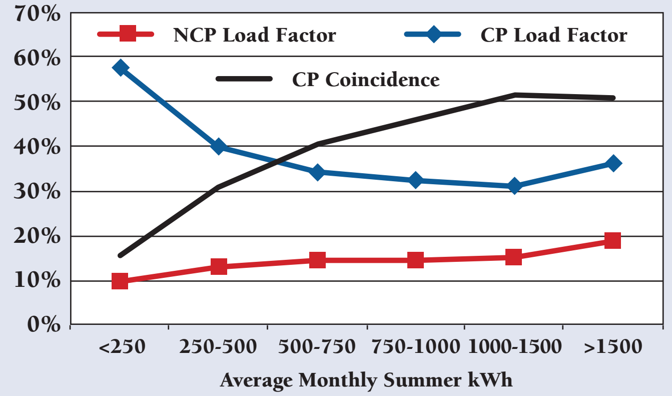
Although demand charges once served the useful function of providing a simple price signal to customers that their peak usage caused long-term costs for capacity to be incurred to meet peak demand even when those resources lay idle most of the time, they may not be appropriate in the presence of current market conditions, smart technologies, and other regulatory policies.[68] Progress with demand response and the development of robust wholesale energy markets allows utilities to meet short-term peak needs with short-term resources, obviating the need for demand charges. Given these conditions, it is more appropriate to utilize more temporally granular time-differentiated rates, in lieu of demand charges. AMI provides an opportunity to move away from the rather crude allocation of cost responsibility afforded by demand charges, and toward a cost recovery framework that is more focused on the costs that utilities and society incur to meet the daily and hourly needs of the system.

A few rate analysts have recommended that demand charges be extended from large commercial customers (where they are nearly universal) to small commercial and residential consumers.[69] Some argue that this is an appropriate way to ensure that solar customers contribute adequately to system capacity costs. This option is inapt for most situations for several reasons:

- The only component of the distribution system that is sized to the demand of the individual consumer is the line transformer, and this is a small portion of the total cost of service.
- Residential and small commercial consumers have high diversity, meaning different customers use power at different times of the day. This is particularly true for multi-family customers, where the utility never actually sees the sum of the individual customer demand on a coincident basis even at the transformer level. Small consumers "share" most of the capacity costs on a utility system. Figure 10 shows how small-use customers have lower contribution to the system ***coincident*** peak (CP), even though (relative to kWh usage) they have higher ***non-coincident*** peak (NCP) demands — which is what demand charges typically are applied to.
- Customer understanding of demand charges is poor among large commercial consumers currently exposed to them, and there is reason to believe that customer understanding would be very poor among residential and small commercial consumers. While a daily as-used demand charge for standby service is likely to be well-understood by an industrial CHP customer, this sophistication does not extend to residential or small

Figure 10

Usage Levels and Customer Coincident and Non-Coincident Peak Demand[70]



68 For example, daily "as-used" demand charges for combined heat and power standby rates may be appropriate. For a discussion of this, see.Selecky, J., et. al. (2014). *Standby Rates for Combined Heat and Power Systems.* Montpelier, VT: Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/7020

69 See, e.g., Hledik, R. (2014). Rediscovering Residential Demand Charges. *Electricity Journal,* 27(7), August-September 2014, pp. 82–96.

70 Presentation of William Marcus of JBS Energy to the Western Conference of Public Service Commissioners, 2015.

commercial users.

- Solar customers may actually contribute power to the grid during peak periods, reducing capacity costs for the system; imposing a non-coincident demand charge would be unfair in that situation. To the contrary, a time-varying NEM tariff automatically credits solar customers for this benefit and a properly designed VOST should do the same.
- The same time periods should apply to both power supply and distribution pricing. There may be periods on weekends when residential distribution circuits are congested even though power supply is not, and asking customers to keep track of two different time-varying rates is likely to be confusing.
- Time-varying prices can more equitably recover actual peak-oriented costs from all customers, including solar customers. Considerable education is needed to assist customers in the transition to default TOU and CPP/PTR pricing. As discussed, a period of shadow billing before the rate taxes effect may be an important element of this education.

A monthly fixed charge based on a transformer rental charge may be appropriate, particularly on rural systems where most transformers serve a single customer. Some utilities already apply this as a "facilities" charge, on the order of $1/kW-month, based either on the customer panel size, the measured demand, or the actual size of the installed line transformer.[71] Our illustrative rate designs include this element, in part to focus attention on how small a demand charge applied to a residential customer should be to recover only customer-specific capacity costs.

Demand charges imposed on non-coincident peak demands are not appropriate for cost recovery of any system costs upstream of the line transformer and coincidence should be tied to utilization of specific parts of the systems where costs are incurred — that is, at the generation, transmission, distribution, or even circuit level — which do not necessarily incur peak usage at the same time. For utilities in restructured markets (where utilities primarily own distribution but not transmission or generation), demand response pricing will be used to provide short-duration capacity at specific points along the distribution system, not to signal investment in generation, transmission, and distribution systems. Even for vertically integrated utilities, the presence of more robust wholesale markets means that these short-term needs can be procured on a short-term basis, rather than on a long-term "build and own" basis. A critical peak or real-time energy price more appropriately recovers this cost of providing short-duration peaking capacity from the consumers using that capacity, without penalizing other consumers whose demand may occur at other hours when high-cost resources are not needed.

Illustrative rate designs for vertically integrated systems are shown in the next section.

Pricing for Restructured Utilities

In general, pricing for restructured utilities would be similar to that for vertically integrated utilities, except that the power supply charges will be separately stated, or even separately billed.

- First and foremost, the monthly fixed charges should not exceed the customer-specific costs incurred.
- Second, demand charges should be used sparingly and only be applied to recover the cost of customer-specific capacity, typically line transformers, primarily for customers having dedicated transformers.
- Third, most distribution costs should be reflected on a TOU/CPP or TOU/PTR basis, to reflect recovery of basic distribution infrastructure costs across all hours, and to reflect recovery of long-run marginal capacity costs to "upsize" that system to meet requirements during on-peak and critical-peak hours.
- Default energy service should have the same time periods and rate differentiation as distribution charges; this avoids customer confusion.
- Consumers desiring a non-differentiated price may be able to contract with a competitive energy supplier to accept the risk of high costs during some periods and bundle the cost of risk management into a contracted price.[72]
- Considerable education is needed to assist customers in the transition to default TOU and CPP/PTR pricing. As discussed, a period of shadow billing before the

71 Manitoba Hydro, for example, imposes a residential customer charge of $7.28 on residential consumers with 200 amp and smaller panels, but $14.56 on consumers with larger electrical panels. Burbank Water and Power (California) implemented a similar approach in 2015.

72 Or some restructured states may offer standard service offer (SSO) customers both a time differentiated and fixed default rate. In this case, competitive retail electric service (CRES) providers will have a market-based price to compete against for both SSO rate types. This approach should exert some market discipline on CRES.

rate taxes take effect may be an important element of this education.

Illustrative rate designs for restructured systems are shown in the next section.

Time-Sensitive Pricing: A General Purpose Tool

TOU Energy Charges Combined with CPP

There are a number of time-varying elements of cost in the generation and delivery of energy. Defined narrowly this would only include recognition that, because the order in which generation is utilized is based on a system of economic dispatch, on-peak power generation will always be the generation with highest short-run marginal cost — that is, the least efficient power plant with highest fuel costs per kWh at that point in time.

The challenge is to set prices that are sufficiently targeted to produce the desired result, without causing too much customer confusion. The more than 100 pilots using time-varying pricing provide clear guidance on this point.[73]

In terms of customer understanding and behavioral response, experience shows that the most effective rate structure is a two- or three-period TOU price, coupled with either a CPP element or a PTR element. This rate design should recover a portion of generation, transmission, and distribution costs in each of the three major time periods, with the recovery of those costs concentrated into the on-peak periods.

Consistent with Garfield and Lovejoy's guidance as introduced earlier, a model TOU rate would ensure that:

- Every kilowatt-hour sold should make some contribution to system capacity-related costs.
- Peak-period and mid-peak-period kilowatt-hours should recover a larger share of system capacity-related costs than off-peak kilowatt-hours.
- The price for the critical peak hours should be based on the cost of operating a demand response program for those hours, because it is less expensive to induce customers to curtail usage for short periods than to build resources for those rare circumstances. But that price, applied to the consumption that does occur, served by resources built for longer periods of service. But that price would generate revenue that would contribute to cost recovery for production, transmission, and distribution costs for kilowatt-hours that flow as well.

Table 6 provides rough guidance as to what costs are reflected in each element of this type of rate design.

Illustrative rate schedules for different classes of consumers reflecting this guidance are shown in Table 7. In these rate schedules, the only demand charges imposed are for customers with dedicated transformers; all other costs are reflected in the TOU energy prices. A CPP rate is demonstrated in combination with TOU prices but not a PTR option. This reflects a judgment that the effectiveness of CPP is demonstrably superior, even though customer acceptance is higher for PTR. The advantage of PTR is that it offer s a no-risk option to introduce customers to

Table 6

Cost Recovery in a TOU Rate Design

	Customer	Off-Peak	Mid-Peak	On-Peak	Peak
Generation					
Baseload		■	■	■	■
Intermediate			■	■	■
Peaking				■	■
Transmission					
Generation-Related		■	■	■	■
Reliability-Related			■	■	■
Economy Energy Related		■	■		
Distribution					
Substations		■	■	■	■
Circuits		■	■	■	■
Line Transformers	?	■	■	■	■
Meters	■	■	■	■	■
Billing and Collection					
Quarterly Costs	■				
Monthly Costs		■	■	■	■
Demand Response					■

73 See Faruqui, A., et al. (2012). *Time-Varying and Dynamic Rate Design.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/5131

Table 7

Illustrative Rates Reflecting Rate Design Principles

Vertically-Integrated Systems

	Unit	Residential	Small Commercial	Medium Commercial	Large Commercial	Primary Voltage Industrial	Transmission Voltage Industrial
		Secondary Voltage Classes					
Customer Charge	$/Month	$4.00	$10.00	$25.00	$50.00	$100.00	$200.00
Off-Peak	$/kWh	$0.070	$0.070	$0.07	$0.07	$0.06	$0.05
Mid-Peak	$/kWh	$0.090	$0.090	$0.09	$0.09	$0.08	$0.07
On-Peak	$/kWh	$0.140	$0.140	$0.14	$0.14	$0.13	$0.12
Critical Peak	$/kWh	$0.740	$0.740	$0.74	$0.74	$0.70	$0.65

Restructured Systems

Distribution Charges	Unit	Residential	Small Commercial	Medium Commercial	Large Commercial	Primary Voltage Industrial	Transmission Voltage Industrial
		Secondary Voltage Classes					
Customer Charge	$/Month	$4.00	$10.00	$25.00	$50.00	$100.00	$200.00
Off-Peak	$/kWh	$0.040	$0.04	$0.04	$0.04	$0.03	$0.02
Mid-Peak	$/kWh	$0.050	$0.05	$0.05	$0.05	$0.04	$0.03
On-Peak	$/kWh	$0.060	$0.06	$0.06	$0.06	$0.05	$0.04
Critical Peak	$/kWh	$0.240	$0.24	$0.24	$0.24	$0.20	$0.15
Default Power Supply Charges							
Off-Peak	$/kWh	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Mid-Peak	$/kWh	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
On-Peak	$/kWh	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
Critical Peak	$/kWh	$0.50	$0.50	$0.50	$0.50	$0.50	$0.50

dynamic pricing and gain their attention and interest.

The disadvantage of PTR is that a utility with a problematic system peak has less ability to measure and hence rely on customer participation as a means of curtailing load during a critical peak event. With CPP, those that use high volumes of electricity during peak periods pay the cost of that usage. This does not occur with PTR, where the cost is spread among all customers if the PTR response is inadequate to curb the rise in peak demand to the extent the utility was seeking. However, the regulator may reasonably prioritize customer acceptance over economic efficiency.

The illustrative rate designs below would yield approximately the revenue level of the average electric utility in the United States today. All of the rates essentially reflect the same costs. All classes served at secondary voltage have separate demand charges assessed for recovery of line transformers, the only system component sized with consideration of individual customer demands. All shared capacity costs are reflected in the TOU rates, so that customers share these costs in proportion to their usage. The larger customers may have very different usage patterns, and benefit (or be harmed) by the TOU rate design, so the average revenue for each class would not be the same, even where the underlying prices may be the same.

An Opt-Out Regime and Customer Education

TOU pricing is a more economically efficient way to charge customers for their electricity use than a fixed average rate, since it tracks more closely to the changing cost of electricity during the day and the on-peak cost of congestion on the transmission and distribution system.

Utility rate experiments have allowed customers to choose whether to participate in the rate pilots ("opt in"), and in those cases where customers had to "opt out" or are forced to be on a rate, there are typically customer protections at the end of the experiment.

From a customer enrollment perspective, however, "default TOU rate offerings are likely to lead to enrollment levels that are 3 to 5 times higher than opt-in TOU rates."[74] The SMUD SGIG-funded project provides empirical evidence that supports offering of time-varying rates to residential customers under default environments.[75] Overall, rates should be lower with time differentiation and CPP because customers would not have to pay a risk premium for the flat rate. Higher participation rates should lead to decreasing system costs that benefit all customers.

The transition to a default TOU and CPP/PTR pricing regime will require extensive customer education. Consideration should be given to the following options:

- **Dual or shadow billing:** Some customers stay on traditional billing, but are shown through their monthly bills what they could save.
- **Customer guarantee:** Each customer could be served on the tariff that provides them with the lowest annual bill during the transition period. If the complex rate results in a higher annual bill, the customer is automatically charged on the basis of the lower-cost rate.
- **"Hold harmless" and first-year bill forgiveness programs:** These provide important consumer protections during a pricing transition.
- **Multi-year data:** The development and deployment of more sophisticated bill comparison software incorporating multi-year individual customer interval data could inform a customer whether their subscription into a certain rate design offered by a competitive retail electricity supplier (CRES) would lead to higher bills than the TOU default rate, and what steps they can take to come out ahead. These could include specific energy-efficiency measures or peak reduction control technology.
- **Best practices:** Utility time-differentiated pilot programs that have worked well provide key lessons.[76]
- **Low-income rate programs:** This option can provide an important safety net for at-risk populations.
- **Deploy targeted energy-efficiency and demand-response programs:** Customers who would be worse off under TOU or CPP rates, especially low-income customers, should be targeted for energy efficiency and demand response programs that can mitigate the impact of those rates, or possibly move them from the "worse off" to the "better off" category.

74 See Faruqui, A., Hledik, R., and Lessem, N. (2014, August). Smart by Default. *Public Utilities Fortnightly.* Available at: http://www.fortnightly.com/fortnightly/2014/08/smart-default; and US DOE, 2015, which states: "Opt-out enrollment rates were about 3.5 times higher than they were for opt-in, and retention rates for both were about the same. While demand reductions for opt-in customers were generally higher, one utility found opt-out enrollment approaches to be more cost-effective than comparable opt-in offers due to significantly higher aggregate benefits and lower marketing costs."

75 George, S., et al. (2014). *SMUD Smart Pricing Options Final Evaluation,* p. 4. Prepared by Nexant for Sacramento Municipal Utility District (SMUD). Available at: https://www.smartgrid.gov/files/SMUD_SmartPricingOptionPilotEvaluationFinalCombo11_5_2014.pdf

76 See: US DOE, 2015; US DOE. (2014, September). *Experiences from the Consumer Behavior Studies on Engaging Customers.* Smart Grid Investment Grant Program. Available at http://www.energy.gov/sites/prod/files/2014/11/f19/SG-CustEngagement-Sept2014.pdf; Lundin, B. (2014). Utilities now have a smart grid customer education model. SmartGrid News, January 8, 2014. Available at: http://www.smartgridnews.com/story/utilities-now-have-smart-grid-customer-education-model/2014-01-08; and PEPCO. (2013, March 19). AMI Implementation Customer Education Plan Phase II. Available at: https://www.smartgrid.gov/sites/default/files/Pepco_Plan_Phase_II.pdf.

V. Rate Design for Specific Applications

Rate Design That Enables Smart Technologies

Smart technologies need smart rate design in order to take advantage of their functionality. Smart meters allow utilities to manage diverse power flows. Smart meters and associated MDMS and SCADA provide the opportunity to achieve multiple benefits, including energy and demand savings and operational benefits. The common elements of utility operating benefits afforded by smart technologies are outlined in Table 8 below.

Table 8

Common Elements of Utility Operating Benefits of Smart Meters[77]

Reduced manual meter reading cost	Improved bill-to-pay time
Reduced problem investigations	Reduced uncollectible bills
Improved meter accuracy	Improved accounting
Reduced meter testing	Call center cost reductions
Elimination of lock rings	Improved asset utilization
Reduced need for use of estimated bills	Outage reporting
Reduced theft	Improved outage management
Improved read-to-bill time	Reduction in lost outage sales
Time-varying pricing for energy cost savings	Dynamic pricing for peak load control
Demand-response enablement	Reduced line losses
Identification of stressed transformers	Improved cost allocation accuracy

Smart meter deployment is expected to reach 91 percent of the United States by 2022.[78] It is important to note, however, that merely installing smart meters does not alone facilitate advanced pricing; MDMS investments, billing engine modifications, and sophisticated rate studies are needed to develop advanced pricing.[79]

Smart meters can enable advanced pricing mechanisms, but given the relative price-variability risks and economic rewards of different types of pricing, the desired consumer rewards of lower bills are applicable only to a subset of pricing options. Figure 11 shows this risk-reward tradeoff, and where smart meters become relevant and useful.

Note that in some restructured states with retail competition and smart meters, metering and billing services can (or must) be provided by a competitive provider.

Apportionment and Recovery of Smart Grid Costs

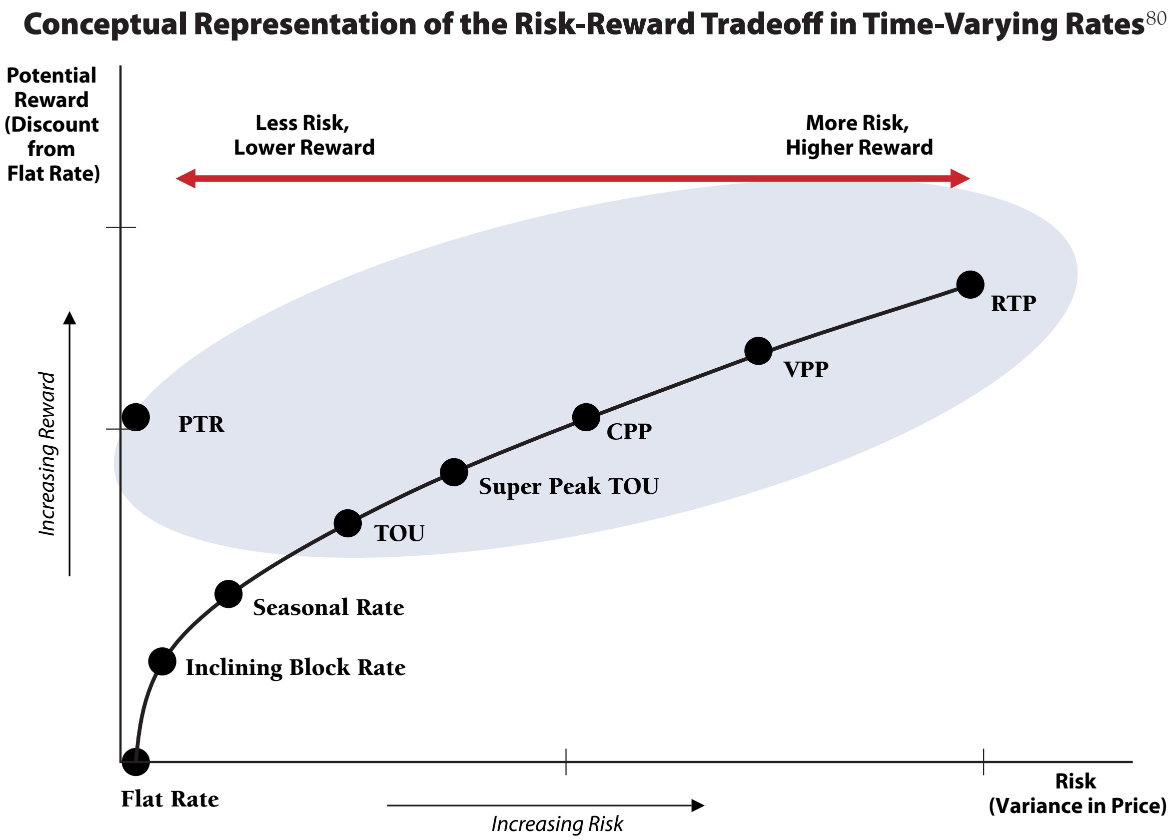
Smart meters, and the support systems necessary for them to realize their full potential, are a costly investment. These costs have been justified by the full spectrum of benefits described above, many of which are related to energy savings, peak load management, and distribution cost controls, not just the billing of consumers.

77 King. C. (2010, October 14). *Making the Business Case for Smart Meters* [Presentation]. Smart Grid Newsletter Webinar, p. 10. Available at: http://assets.fiercemarkets.net/public/smartgridnews/eMeter_Oct_14_2010_Biz_Case_Rev3_1_.pdf

78 Telefonica. (2014, January). The Smart Meter Revolution: Towards a smarter future. Available at: https://m2m.telefonica.com/multimedia-resources/the-smart-meter-revolution-towards-a-smarter-future.

79 Lazar, 2013.

Figure 11



Therefore, these additional costs of smart meters should not be recovered in fixed monthly charges. Traditionally, in utility cost analysis, "meters" were considered a customer-related cost, allocated based on the number of customers in each class because each customer typically required one meter. Those costs were typically reflected in rates as part of the monthly customer charge.

When those meters only performed the function of providing input to the billing system, this made sense; however, smart meters are very different. Because of all of the non-billing functions that smart meters provide, a portion of the cost of smart meters and the associated data collection and data management system should be treated as energy costs, peak load management costs, distribution system reliability costs, or other types of costs, not just as customer-related costs. Smart meter functions related to capacity, reliability, or other aspects of the electric system should be recovered in the same manner as other investments made for those purposes.

Charges associated with connection and disconnection of customers are usually separately billed. Accordingly, the costs of smart meters allocated to these functions should not be included in monthly fixed charges, but should recovered through separately billed fees. Table 9 reflects the appropriate classification of costs associated with some of the more important smart

Table 9

Cost Classification Appropriate for Smart Meter and MDMS Costs

Smart Meter and MDMS Facilitates	Classification Basis
Time-Differentiated Pricing (TOU)	Energy and Demand
Dynamic Pricing (CPP), Demand Response	Demand
Bidirectional Measurement	Energy
Distribution Optimization	Capacity and Energy
Remote Disconnection and Reconnection	Separately Billed, as Applicable

80 Adapted from Faruqui et al., 2012.

meter and MDMS functions.

Smart meters and the associated MDMS perform multiple functions. The costs associated with smart grid investments should be apportioned so that all aspects of utility service that benefit share in the costs. Simply stated, to justify deployment of smart meters and an MDMS, there should be an expected net savings to the utility customers over the life of the investments. No single category (energy, capacity, customer) should be assigned costs that exceed that particular benefit. These multiple benefits should mean that the customer billing function is at least no more costly than before deployment of the new systems and, in fact, given the expected savings in the billing and customer service costs, should reflect a net savings in the long run. At the time of smart meter installation, the monthly fixed charge for billing and collection functions should therefore be reduced, to reflect the multiple anticipated benefits of a smart meter implementation. This could take place in a general rate case or during the smart grid ramp-up in a net of benefits rider that would reduce not only the monthly customer charge, but also the capacity and energy-related charges to reflect the total benefits, net of incremental costs.

To date, three separate approaches have been used for smart grid cost recovery. They are special purpose riders, riders with limits based on expected economic benefits, and traditional rate case treatment, which is subject to a prudence review.[81] The risk to consumers is greater with special purpose riders without limits and less when the utility is required to file a rate case. In a net of benefits rider approach, the smart grid investment risk is shared between customers and utility shareholders by putting the utility at risk to actually achieve the promised cost savings. In all cases, smart grid costs should be apportioned so there is a net savings to the customer billing, energy and capacity classification to reflect the multiple benefits of a smart grid implementation; in essence — rates and bills should decline as a result of smart grid deployment. This can take place in a general rate case or during the smart grid ramp-up, in a net of benefits rider. A number of regulatory examples are instructive:

- Duke Energy Ohio Smart Grid Audit and Assessment/ Ohio PUC: calculated $383 million in net present value operational benefits over a 20-year period.[82] Duke Energy Ohio agreed to reflect a total of $56 million in operational benefits for the years 2012 through 2015 in their existing net of benefits smart grid rider,[83] and to account for all benefits in the next rate case.[84]
- California Public Utilities Commission (CPUC) / Southern California Edison: $1.4246/month in smart operational benefits with each smart meter that the utility puts into service. The Southern California Edison Co. was required to credit $1.4246 of the operational benefit per month beginning eight months after the smart meter is reflected in rate base.[85]
- Oklahoma Corporation Commission/Oklahoma Gas and Electric: Immediate deduction of operational savings from the revenue requirement when smart grid systems went into service.[86]

Smart Rates for Smart Technologies

The term "smart rates" is used here to describe those rate designs that require the type of data collection that smart meters provide, and which are expected to produce significant peak load reductions, reduced energy consumption, improved system reliability, improved power quality, and reduced emissions. These include:

- TOU (with and without technology, such as in-home displays);
- PTR (with and without technology);
- CPP (with and without technology); and
- RTP (with and without technology).

Aside from the TOU-oriented rate designs, payment and credits based on specific services, such as the provision to voltage regulation, spinning reserves, frequency control or other ancillary services will need to be provided.

81 Alvarez, P. (2012). Maximizing Customer Benefits: Performance measurement and action steps for smart grid investments. *Public Utilities Fortnightly*, January 2012, p. 33. Available at: http://www.fortnightly.com/fortnightly/2012/01/maximizing-customer-benefits

82 The MetaVu Duke Energy Ohio audit report includes 26 separate operational benefit categories. See MetaVu. (2011, June 30). Duke Energy Ohio Smart Grid Audit and Assessment, p. 72. Available at: https://www.smartgrid.gov/files/Duke_Energy_Ohio_Smart_Grid_Audit_Assessment_201104.pdf

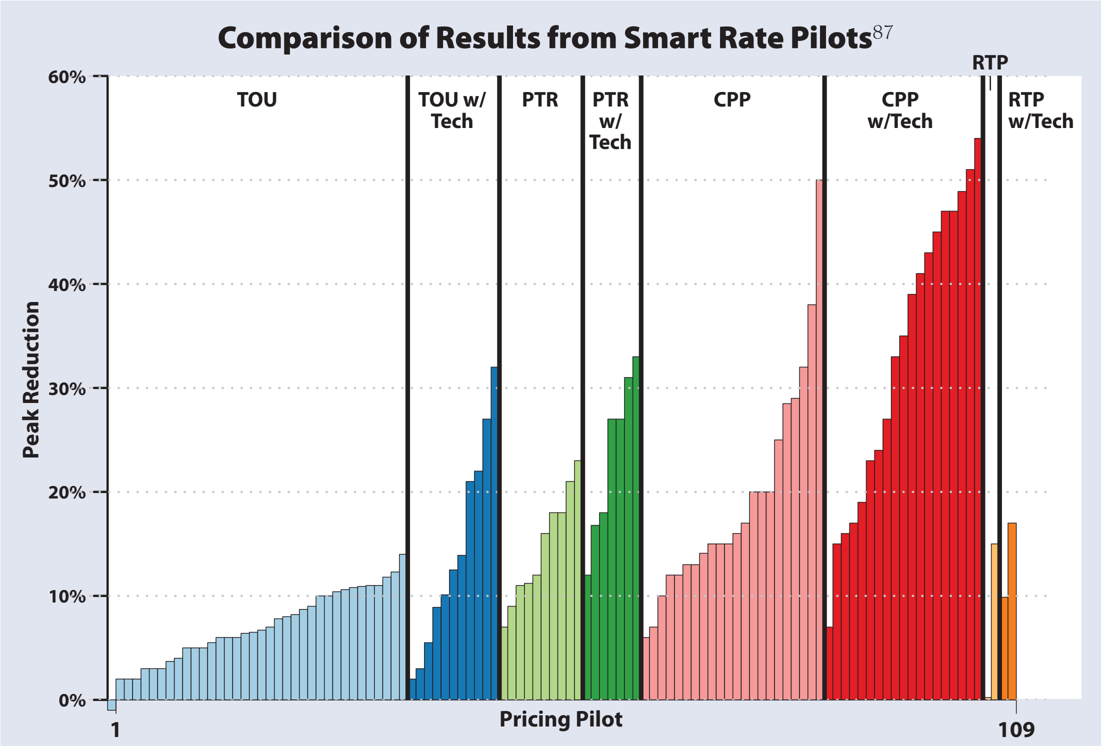
83 Settlement filed in Duke Energy Ohio Case No. 10-2326-GE-RDR.

84 Ibid.

85 CPUC Decision No. 08-09-039 (September 18, 2008), pp. 37-38.

86 Alvarez, 2014, p. 258.

Figure 12



years and consecutive events."[88] Furthermore, enabling technologies (in-home displays, smartphone applications, smart thermostats, and appliances) enhance price responsiveness. TOU and CPP rates may also be fairer to customers than traditional flat rates because customers who contribute more to the increased costs of peak usage are made to pay more.[89]

By having rates that reflect system value, customers can and will take action that over the population and over time will reduce system costs, and in so doing reduce costs and thus rates for everyone. Overall then, rates should be lower with time differentiation and critical peak pricing. Utility rates include both an operating expense provision and a risk element in the rate of return to enable the utility to purchase high-cost energy as needed during extreme periods. Because customers are directly bearing this risk at the time it is experienced, the base rates for non-critical periods will logically decline slightly.

A demonstration of the power of rate design in influencing customer behavior is depicted in Figure 13, which shows results of 30 different pilot programs. The impacts on reductions in peak demand are grouped by rate type and whether customers have enabling technology.

The effectiveness of different TOU rate designs varies considerably. Figure 12 shows a comparison of pilot program peak reduction results for a variety of smart rates. CPP rates clearly show the greatest promise of delivering strong peak reductions by customers.

Looking Ahead: Smart Houses, Smart Appliances, and Smart Pricing

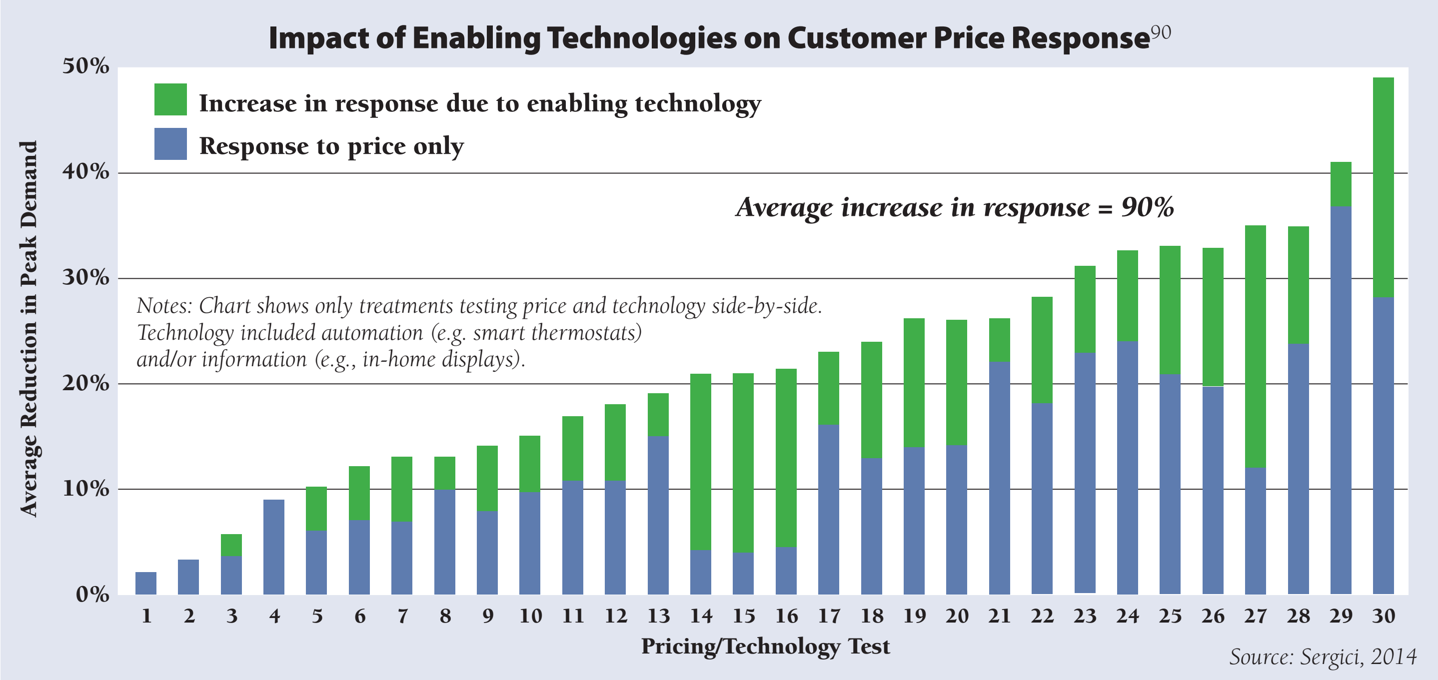
Evidence shows that advanced pricing works best with technology enhancement to enable automated response to higher prices that can tie directly into time-differentiated prices. Over 200 time-differentiated rate tests have been conducted worldwide, with differing results. The consensus of these pilot programs is that customers respond to prices. The modified consumption patterns "persist across several

87 Faruqui et al., 2012.

88 Sanem Sergici, S. (2014, August 6). *Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments* [Presentation]. The Brattle Group, p. 6. Available at: http://www.nga.org/files/live/sites/NGA/files/pdf/2014/1408MichRetreatDynamicPricing_Sergici.pdf

89 Traditional flat rates force all customers to a rate based on the average costs assigned to the class, to the detriment of customers who use less on-peak and, therefore, have less costly consumption patterns.

Figure 13

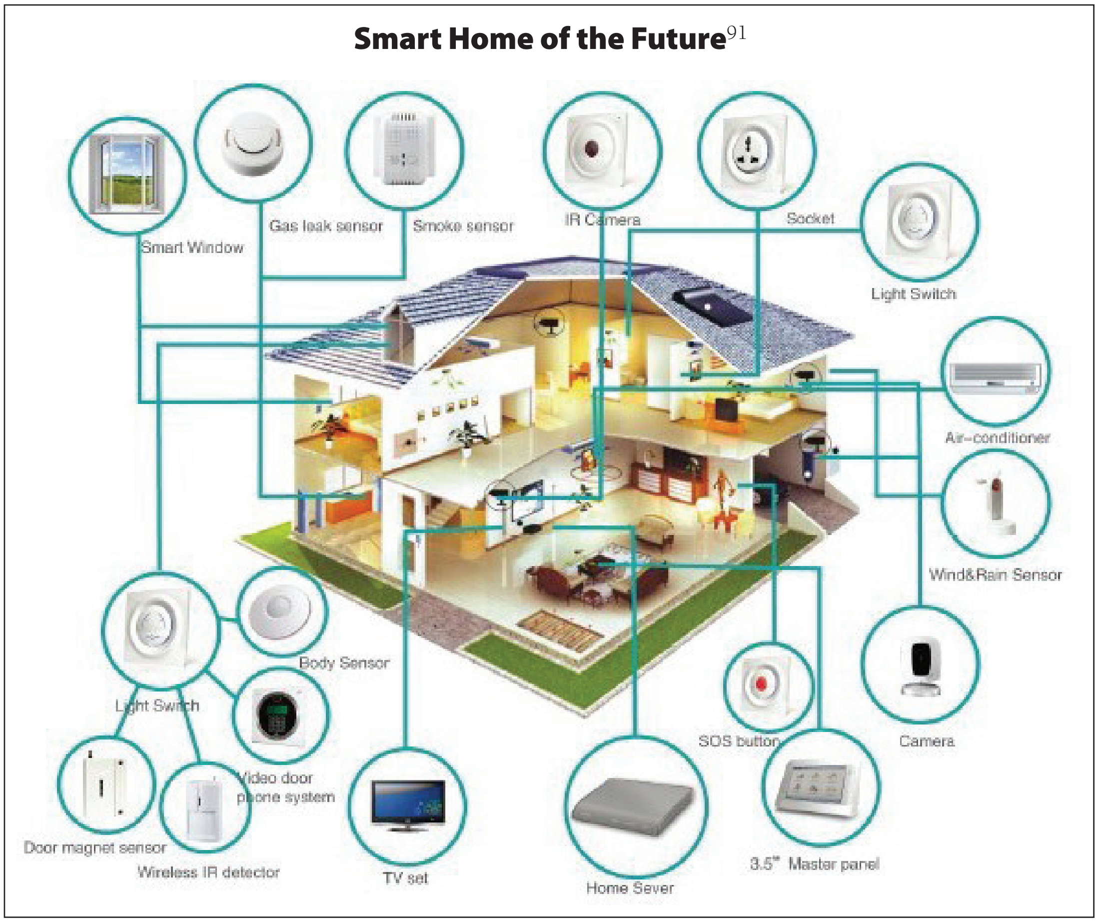


Pricing Signals for Smart Appliances

Figure 14 reflects the multitude of smart appliances in a smart home. In order to fulfill their smart functions, most of these appliances must be integrated into an energy management system, which responds to the dynamic pricing signal of the underlying rate design or connects to a customer preferences profile.

A number of technology companies are developing products that interface with a utility's smart grid deployment. General Electric, for example, has developed smart appliances that communicate with their smart thermostat to manage appliance electricity usage based on real-time utility pricing.

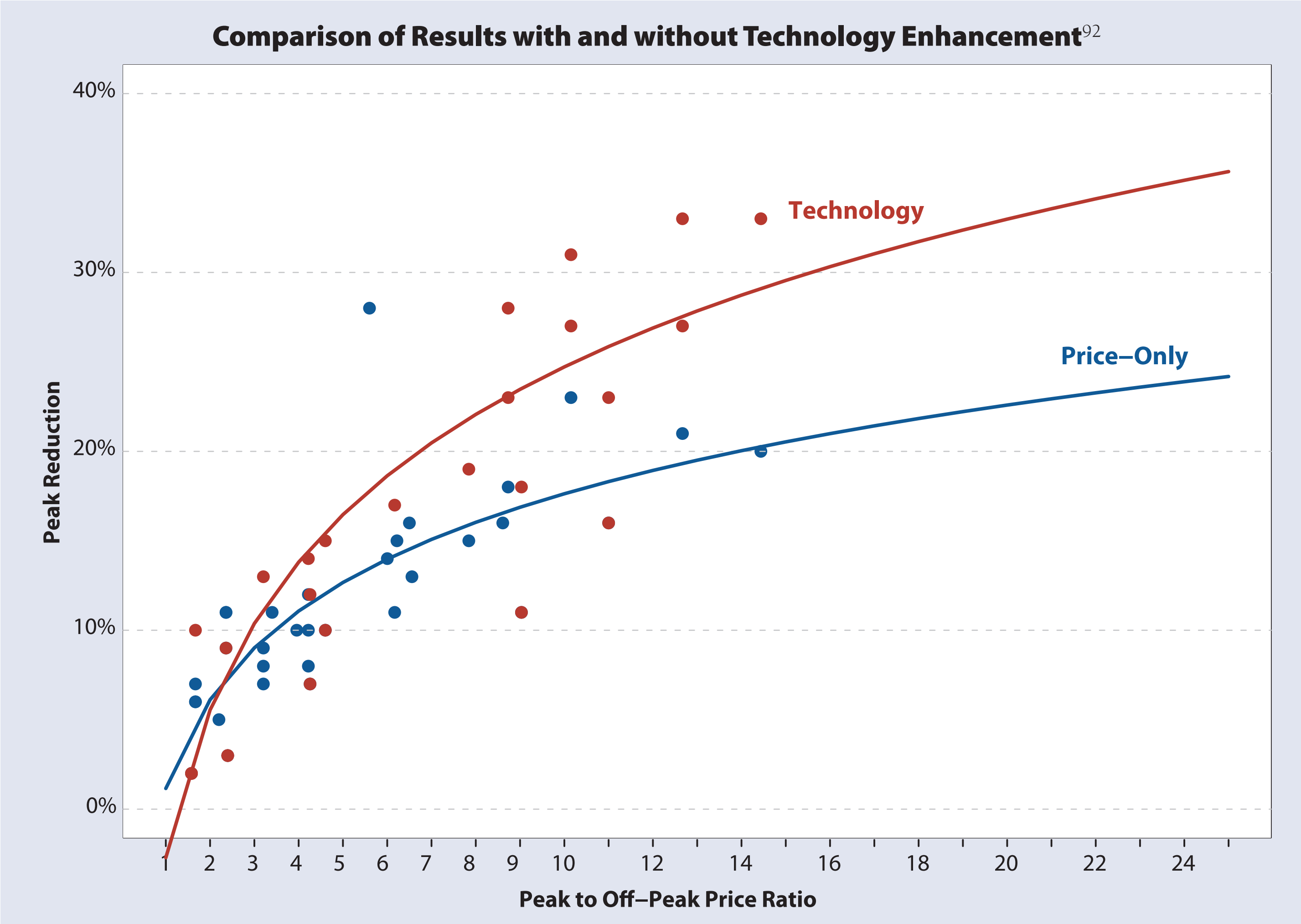
Figure 14



90 Sergici, 2014, p. 4.

91 Source: SmarterUtility.com

Figure 15



Energy Management Systems and Dynamic Pricing

In order for homes to respond to dynamic pricing, either manual customer intervention or automated technology needs to be deployed. As reflected in Figure 15, experience shows that automated technology provides greater energy benefits by far. To achieve this, energy management systems, smart appliances, or both are required.

Rate Design for Customers with Distributed Energy Resources (DER)

The term DER includes energy efficiency, distributed generation, and demand response. Realization of the potential benefits of DER requires TOU/CPP (or PTR) rate design.

Value of DER Pricing

Historically, customers were not given any price signal about the value DER provides the electric system. DG, energy efficiency, and DER were largely ignored by utilities and regulators. This changed in the late 1970s with the passage of the Public Utilities Regulatory Policies Act (PURPA), which provided for mandatory purchase of power from customer-sited generation,[93] or what we now call an FiT. It also changed with early efforts to increase end-use energy efficiency and bring it within the realm of system planning processes, through the concept of integrated resource planning (IRP).

Today, energy efficiency and demand response are recognized as important resources on the electric grid and

92 Faruqui, et al., 2012, p. 32.

93 Through payments for DG at the utility's avoided generation cost, a precursor to the FIT.

customer-sited DG is on an accelerated course to become an important generating resource. DER enables the displacement of generation, transmission, and distribution costs on a cost-effective basis. To take advantage of this, appropriate rate design and planning processes will need to be in place.

DER Compensation Framework

A number of compensation mechanisms have been considered by regulators for distributed resources. They range from value to grid approaches using avoided costs to the establishment of a system of distribution credits.[94] What value the distributed resource provides to the grid is determined using avoided cost calculations that can be made systemwide or, preferably, are location specific. While the former uses an average rate for DER, the latter is based on location-specific costs and projected growth rates.

Locational Value of DER

Postage stamp rates are a form of cost averaging among customers in the same rate class that is taken for granted by many rate analysts. Urban and multi-family customers require less investment in distribution facilities per customer or per kilowatt-hour than suburban and rural customers, but nearly all utilities charge all residential customers the same rates and do not distinguish on that basis.[95] Customers with overhead distribution service are cheaper to serve (but have more outages) than customers with underground service. But with nearly all utilities both pay the same rates. Customers with low usage may use only their ratable share of existing low-cost resources, and not require the more expensive new resources that drive many rate increases.

Providing incentives or preferential pricing for DER located in areas of congestion can be beneficial to the distribution system. Critically sited and timely DER can lead to the postponement or avoidance of costly upgrades. A distribution utility would have to make known preferential locations to prospective DER developers and provide some form of incentive.[96]

Some of the earliest energy-efficiency programs operated by electric utilities were directed at locations with impending reliability problems due to distribution system constraints.[97] "Hot spots" on the distribution system stem from congestion linked to overloading of the distribution infrastructure. Locational marginal pricing (LMP) provides a mechanism for revealing the cost of supplying the next unit (e.g., megawatt) of load at a specific location or node in order to send a price signal for avoiding or eliminating congestion. It takes into account bid prices for generation, the flow of power within the transmission system, and power transfer constraints.[98] LMP is a tool targeted primarily at organized hourly or daily wholesale markets, although its underlying framework is applicable at the retail level. However, retail customers are not typically in a position to respond to a dynamic LMP regime. An approach tailored to the retail market is required to implement the concepts of LMP at that level.

The pragmatic way to reflect locational values to residential and small commercial consumers is through targeted incentives for peak load management, as are typically provided by energy-efficiency suppliers and demand response aggregators, not necessarily through complex retail rate designs that consumers may be

94 Moskovitz, D. (2001, September). *Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Consumers and Vendors.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/docs/RAP_Moskovitz_DistributedResourceDistributionCreditPilotPrograms_2001_09.pdf

95 Commonwealth Edison and NV Energy are notable exceptions, with lower rates for multi-family consumers.

96 The State of Vermont, for example, designates specific areas for Efficiency Vermont to target with peak load reduction measures each year. See https://www.efficiencyvermont.com/About-Us/Energy-Efficiency-Initiatives/Geographic-Targeting. See also Greentech Media. (2014, July 21). Con Ed Looks to Batteries, Microgrids and Efficiency to Delay $1B Substation Build. Available at: http://breakingenergy.com/2014/07/21/con-ed-looks-to-batteries-microgrids-and-efficiency-to-delay-1b-substation-build

97 Tacoma Power, 1979, and Snohomish Public Utility District, 1983-84, both concentrated energy efficiency on electrically heated homes located on stressed distribution substations.

98 Arsuaga, P. (2002). Primer on LMP. Available at: http://www.elp.com/articles/print/volume-80/issue-12/power-pointers/primer-on-lmp.html. A nodal price in an LMP system is the incremental increase in total system cost associated with supplying the next increment of load at a specific location or bus. In a constrained system, the next increment of load at a given bus is typically supplied by adjusting the output of more than one generator, each contributing to the load in a ratio dictated by the physical attributes of each system and the location of the bus relative to other elements in the system. Typically, the output of some generators must be decreased when the output of other generators is increased, to prevent the flow on constrained lines from exceeding the constraint.

unlikely to understand. Candidate zones are those that are approaching the maximum capacity of the affected part of the grid, with low to moderate growth rates over the medium to long term.[99] When DER is placed in a congested area or otherwise desirable location with respect to the grid, a pricing approach based on the utility's avoided costs provides compensation to the DER customer. In this manner, DER that is tactically located and more valuable to the utility will receive greater compensation than DER that is built simply to serve a customer's generating load. One way to compensate the customer is through the use of a distribution rate credit, which pays a premium (above the generally applicable rate) for distributed resources that locate in an area targeted for near-term distribution upgrades and which accommodate postponement or avoidance of the upgrade. The same is true for other DER resources such as demand response and energy efficiency.

All of these scenarios offer opportunities for better association of costs with prices. The question for regulators may be more a matter of customer acceptance than one of theory, because customers located physically close to one another, but served on different distribution circuits, would see different pricing and programmatic incentives. In addition, regulators would want to consider whether the costs associated with any form of location pricing, especially where whole new rate classes are created, is worth the benefits to the affected customers.

Other Benefits of DER

Separating out the existing cost analysis into its constituent parts — energy, demand, and ancillary services — can also support smarter demand response and DER investment. Providing a market for DER-provided ancillary services will support DER investments that help the grid's reliability and resiliency. For example, Germany (and a current proposal in Hawaii) requires smart solar inverters to perform certain functions, such as power ramping and volt/VAR control, which lead to more grid stability and improved power quality. DER with smart inverters are more expensive, but more valuable than DER with older inverters and should be compensated for providing that value.

Recovery Strategies for DG Grid Adaptation Costs

Recovering the costs of grid modifications associated with DG is a topic of considerable controversy. Even without a need for grid modification, in the absence of a revenue restoration mechanism such as decoupling (see "Revenue Regulation and Decoupling"), solar installations operated with NEM reduce utility revenues and may result in reallocation of non-generation costs to remaining consumers if growth on the system does not absorb these costs. With very high levels of renewable energy, additional distribution system and generation costs will likely be incurred to integrate more distributed and intermittent resources. Utilities and consumer advocates may seek to recover these costs during the hours that DG customers are net consumers from the grid. However, whether this is appropriate depends on the associated benefits that DG provides to all non-DG customers.

In Hawaii, where these modifications are more imminently needed, Hawaiian Electric has proposed a significant revision in compensation to solar generators as part of a proposal to raise the cap on allowed levels of solar installation. The Hawaiian Electric proposal in the short run includes lower compensation to new solar producers for power fed to the grid, and in the long run includes higher monthly fixed charges to recover grid costs. The reaction has been hostile from affected interests — consumers and the solar industry alike. The Hawaii PUC Chairman reached an agreement[100] with Hawaiian Electric to resume rapid approval of solar connections, but without approval of the lower compensation for power fed to the grid; consideration of higher fixed charges was retracted by the utility in the context of a pending merger application.

This work in Hawaii may be a postcard from the future for mainland utilities. The overall plan to adapt to high levels of DG in Hawaii, motivated in large measure by a determination to dramatically reduce the amount of fuel oil required by the Hawaiian economy,[101] includes

99 See Shirley, W. (2001). *Distribution System Cost Methodologies for Distributed Resources.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGeneration_2001_09.pdf

100 Hawaii PUC. (2015, February 27). PUC Chair and HECO President Sign Agreement to Address Residential PV Interconnection [Press release]. Available at: http://puc.hawaii.gov/wp-content/uploads/2015/03/NewRelease.20150227.pdf

101 For more detail on the Hawaii Clean Energy Initiative, see: http://www.hawaiicleanenergyinitiative.org/about-the-hawaii-clean-energy-initiative/.

the following examples of grid modifications, beginning adjacent to the consumer premises and working upstream:

- **Line transformer:** Line transformers must be sized to handle the maximum flow in either direction. Where multiple residential or small business consumers share a transformer, the transformers are normally sized based on the estimated coincident peak usage or DG generation of the customers served by that transformer. This is significantly less than the sum of the individual customer peaks, because different consumers use power at different hours. However, if all of these customers have solar systems installed, it is more likely that they will be exporting simultaneously, and it is possible that the transformer may need to be sized to their coincident export peak, which can be larger than the consumption peak for which transformers have historically been sized. A customer-specific transformer charge is one approach for allocating and recovering the costs of such a resized transformer; a simple TOU tariff for all delivery service is another. Our basic rate design provides for direct recovery of line transformer costs from the customers using them, so a solar customer that requires an augmented line transformer capacity will bear this cost directly.
- **Circuit capacity:** Until installed solar significantly exceeds the circuit capacity, upgrades to circuit capacity will not be required. Even when the solar systems are producing their maximum output, as long as some of that generation is consumed on site at some of the generating locations, the circuit capacity will not be exceeded by exported power. However, if installed solar rises to exceed the sum of the circuit capacity plus the amount consumed on site during periods of peak generation, circuit upgrades of conductors may be required. Nevertheless, even Hawaiian Electric, depicted above, has estimated that installed solar can safely reach 250 percent of the minimum daytime load without requiring major circuit modifications if smart inverters are required.
- **Smart inverters:** Hawaii is requiring that new inverters be capable of "riding through" system disturbances, avoiding a situation where a failure of a resource on one part of the system results in other resources tripping off-line, compounding a minor outage. Requiring new inverters to also include the ability to provide voltage and frequency support to the grid may be cost-effective, and should be considered. If they are required, compensation to the owner for the value of these services needs to be addressed.
- **Voltage regulation:** High levels of solar penetration result in power being injected into the distribution circuits at different points at different times of the day. If power flows downstream from the substations to loads during non-solar hours, and upstream to substations from distributed generators during the solar day, it may be necessary to install voltage regulators at additional points along the distribution circuit. While not prohibitive in cost, these can add up across an entire electric utility service territory. At the same time, these devices enable avoidance of central station generation, transmission, and distribution substation upgrades, which are far more expensive, so all consumers generally benefit.
- **Substations:** If and when an individual circuit is generating more power from distributed generation than the consumers on the circuit are using, power will flow to the low-voltage bus of the distribution substation. In urban and suburban areas, where multiple circuits connect at the bus, excess power will simply flow to the other circuits on that bus. The substation itself will only experience a lower level of demand for power supplied from the transmission side of the substation. If flows exceed the demand of all circuits combined — something that might occur when 20 percent or more of the consumers served by a substation have PV installations — then the power will flow "backward" through the substation, meaning what is normally a step-down function becomes a step-up function. Substations may need additional voltage regulators installed or, in an extreme case, a replacement multi-tap station transformer, to accommodate reverse flows. New station transformers deliver line loss reductions and other benefits that may fully offset the incremental costs.
- **Generation:** On most utility systems in the United States, many utilities are interconnected in large networks, with tens of thousands of megawatts of interconnected generating units dispatched to meet demand in an economic fashion. Simply by retiring older, less-flexible steam generation; adding more flexible newer generation; and implementing cost-effective energy efficiency programs, demand-response programs, time-varying prices, and greater inter-regional cooperation, most regions can adapt

their power supply to a high-renewables future.[102] On island systems, like Hawaii, this is more challenging, and deployment of electricity storage may be an important component of this transition.

- **Demand response:** Most regions of the United States have begun implementing demand response programs to reduce loads during extreme circumstances. More innovative programs, like grid-integrated water heating and storage air conditioning may be cost effective ways to add flexibility to better enable adaptation to a high-renewables future.[103]

Hawaii may be leading the nation in change, but dockets have been convened in Arizona, Colorado, California, New Mexico, and other states examining the appropriate way to recover grid costs from DG customers, including the cost of grid modifications needed to adapt to high levels of solar. In general, regulators will be faced with the following issues:

- **Value of solar:** Should the value of solar energy, including avoided generation, transmission, distribution, fuel cost risk, fuel supply risk, environmental benefits, and other factors be considered?
- **Recovery of existing distribution costs:** Should existing distribution costs be recovered volumetrically, or through some sort of fixed charge or demand charge?
- **Recovery of incremental distribution costs:** If grid modifications are incurred to adapt to increased penetration of customer-sited DG, will these costs be recovered directly from the DG customers or spread to all distribution customers?
- **Recovery of stranded generation costs:** If demand for grid-supplied power decreases, will solar customers bear a share of cost recovery for generating resources that are retired? Will non-DG (grid-dependent) customers bear these costs?[104]
- **Recovery of new generation costs:** If new flexible generation must be added to serve the more variable usage of solar customers (zero during the solar day; unchanged, i.e., traditional consumption at night), should these costs be recovered from all customers or only from solar customers?

The outcome of these investigations will produce different results, state by state. In general, states looking ahead at marginal costs will recognize that solar customers are bringing great value to the system and will enjoy lower costs over the long run, while states focused on embedded cost concepts will see stranded cost issues, but experience higher costs over the long run.

Following the guidelines below should ensure that solar and other residential consumers are treated equitably:

- **Customer charges:** Should not exceed the customer-specific costs associated with an additional customer, such as the service drop, billing, and collection.
- **Energy charges:** Should generally be time-varying and those time differentiations should apply both to power delivered by the utility to customers and to power delivered to the utility from customer generation. This assures that solar output is valued appropriately, and high-cost periods are reflected in the prices charged to customers using power at those times. It may be appropriate to make time-varying rates mandatory for solar customers, but optional for small-use non-solar customers.
- **Minimum bills:** Where utilities have high numbers of seasonal customers who only consume power during the summer or winter, an annual minimum bill may be an appropriate rate design to ensure a minimum level of revenue from customers in this category. However, minimum bills are not a particularly desirable rate design as a rule.[105]
- **Demand or connected load charges:** Demand charges are only relevant for recovery of the relatively

102 See Lazar, J. (2014). *Teaching the "Duck" to Fly.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6977

103 See Cowart, R. (2003). *Dimensions of Demand Response.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/docs/RAP_Cowart_NEDRIOverview_2003_11.pdf; and Taylor, B. and Taylor, C. (2015). *Demand Response: Managing Electric Power Peak Load Shortages with Market Mechanisms.* Beijing: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7527

104 This is normally a question for vertically integrated utilities and not for restructured utilities, where the generation is supplied separately by unregulated suppliers.

105 See Lazar, J. (2015). *Electric Utility Residential Customer Charges and Minimum Bills.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7361

small capacity costs of line transformers that are sized to the demand of individual customers. They are never appropriate for upstream distribution costs that can be recovered in a TOU rate. The illustrative rate designs apply demand charges only for line transformers, recovering all other capacity-related costs instead in TOU and CPP rates.

- **Low-cost utilities (average revenue <$.10/kWh):** May need to retain or institute inclining block rates to ensure that the end-block of usage reflects long-run marginal costs for clean power resources, transmission, and distribution.
- **Most (average-cost) utilities (average revenue $.10 - $.20/kWh):** Conventional net metering (of the full rate, including volumetric charges for power supply and distribution) is likely an appropriate strategy; while grid operators lose distribution revenues, their consumers gain all of the other benefits of increased renewable generation, and, taken as a whole, the value of solar energy added to the system is equal or greater in value than the retail electricity price.
- **High-cost utilities (average revenue > $.20/kWh):** Utilities with average residential prices in excess of the long-run marginal cost of new clean energy resources ($.10/kWh to $.25/kWh) may need to reflect distribution charges separately. For example, these rare high-cost utilities may need to apply distribution charges to all customers for the power they receive from the grid, then crediting only a power supply rate when solar power is fed to the grid. As emerging technologies become more mainstream, rate designs will need to adapt to changes in how customers use electricity and how these technologies impact the grid. DG can be viewed as a tool to strengthen the grid and rate designs of the future can encourage the utility-customer partnership to ensure the efficiency and economy of the grid. Key will be the temporal rates discussed above; but also innovations in terms of unbundling customer-generated power to provide ancillary services. Providing credits to DER strategically located to support the grid will be important. Rate designs of the future can incorporate these win-win strategies to the benefit of all stakeholders.

Rate Design for Electric Vehicles

EV Pricing without AMI

Many electric utilities offer TOU pricing to customers without fully deploying AMI. They typically install interval TOU meters that can be read manually, and some offer special pricing to EV customers. An example is the Los Angeles Department of Water and Power (LADWP), whose standard residential rate and EV rate are shown in Table 10. The EV rate is separately metered, and discounted from the optional TOU rate by excluding the customer charge ($8.00/month) and discounting the otherwise-applicable energy rates.

EVs with AMI

A utility with AMI has many options for providing a rate for EV owners that is appealing to the customer and remunerative to the utility. These can include a simple TOU rate, a multi-period TOU rate with a super-off-peak period, a critical peak pricing rate, or a real-time price. Each of these is discussed in Appendix B (“Rate Design for Vertically Integrated Utilities”). A relatively unique option,

Table 10

LADWP Standard Residential Rate and Electric Vehicle Rate March, 2015

			Optional TOU Rate			Electric Vehicle Rate		
	Summer	**Winter**		**Summer**	**Winter**		**Summer**	**Winter**
Customer Charge	None	None		$8.00	$8.00		None	None
First 350 kWh	$0.146	$0.146	**High-Peak**	$0.246	$0.149	**High Peak**	$0.220	$0.141
Next 700 kWh	$0.175	$0.175	**Low-Peak**	$0.166	$0.149	**Low-Peak**	$0.141	$0.141
Over 1,150 kWh	$0.216	$0.175	**Base**	$0.131	$0.135	**Base**	$0.107	$0.107
Minimum Bill:	$10.00	$10.00				**Minimum Bill**	$10.00	$10.00

Source: Los Angeles Department of Water and Power grid-operator controlled charging, would allow the EV owner to request an "economy charge" by a defined time (7 am, for example) and then the grid operator would ensure the vehicle was charged by the time required by taking advantage of the communication technology in the vehicle's charge controller and using the lowest-cost available hours during the charge window. The grid operator can thus spread the charging load among a diversity of EVs, and vary the battery charging rate from minute to minute to supply voltage support and frequency regulation ancillary services to the utility, further reducing the cost of service to charge EVs.

Public Charging Stations and Time-Differentiated Pricing

EV owners sometimes need to charge during the day, or when they are away from home. To do so, they need to be able to take advantage of public charging stations. The pricing schemes for public charging and workplace charging vary widely from, and include the following:

- **Free charging:** Some utilities, public agencies, and retailers offer free public charging. For the utilities and agencies, this is an overt effort to stimulate EV sales and reward EV owners. For retailers it may be a sales tool: By offering free EV charging, the retailer can attract a presumably upper-income consumer to spend an hour in their business — with an implicit assumption that the expected increased sales will more than offset the electricity cost.
- **Hourly parking:** In states where the regulation of electricity prices precludes the resale of electricity for vehicle charging, owners of EV charging stations commonly avoid regulation by charging hourly for parking, and charging nothing for the electricity. The hourly pricing can be time-differentiated to reflect both power supply costs and consumer demand for charging.
- **Time-differentiated pricing:** Some owners of EV charging stations impose time-varying rates per kWh for EV charging, corresponding to wholesale market or utility TOU prices.

To ensure that EV charging station operators are able to implement time-varying prices, regulators and legislators need to consider whether the public interest is served by imposing regulation on EV charging,[106] or whether that will discourage the availability of EV charging stations and thus suppress the EV market. Implicit in this consideration is whether the free market will function appropriately so that price regulation is not needed.

Regulators will need to determine if the public benefit of providing an infant industry subsidy to EV charging is consistent with the public interest. This consideration goes well beyond the electric utility pricing realm, into broad areas of energy security, environmental policy, and economic development.

Vehicle-to-Grid and Full System Integration of EV (Maryland/PJM RTO Pilot)

One of the great promises of EVs is that they will become fully grid-integrated, providing a market for off-peak power, a source for on-peak power, and multiple ancillary services.[107] This requires a combination of sophisticated charging units in vehicles, complex pricing, and a *very* smart grid.[108] Commonly called Vehicle-to-Grid (V2G), experiments to demonstrate this concept are underway in Maryland and Delaware through a partnership among Honda, the University of Delaware, and Delmarva Power.[109] There are many questions being addressed, including the impact of utility use of vehicle batteries on battery life, compensation mechanisms for both energy storage and ancillary services as vehicles move from service territory to service territory, and methods to ensure that EV owners always have the energy they need to reach their planned destinations. While smart charging offers imminent benefits to the grid, V2G technologies will require more time to develop.

106 Regulators can pay attention to how all customers are affected by vehicle charging, and if costs for vehicle charging are spread to all customers, it should be because all customers are likely to benefit sooner or later.

107 For a discussion of this potential, see Lazar, J., Joyce, J. and Baldwin, X. (2007). *Plug-In Vehicles, Wind Power, and the Smart Grid.* Available at: http://www.raponline.org/docs/RAP_Lazar_PHEV-WindAndSmartGrid_2007_12_31.pdf

108 Ibid.

109 See University of Delaware. (2014). UD, Honda partner on vehicle-to-grid technology [Press release]. Available at: http://www.udel.edu/udaily/2014/dec/honda-delaware-v2g-120513.html

Green Pricing

Green pricing is an optional utility rate or service that allows customers to support a greater level of utility company investment in renewable energy technologies. Participating customers typically pay a premium on their electric bills to cover the incremental cost of the additional renewable energy.[110] The funds gathered from green pricing programs are either used to develop renewable energy projects or to support existing projects by purchasing renewable energy certificates (RECs).[111] Approximately 850 utilities — including investor-owned, municipal utilities, and cooperatives — offer a green pricing option.[112]

In restructured states, a number of Competitive Retail Electricity Suppliers (CRES) offer green products such as 100 percent wind. Interestingly, these products are very competitive with other supply options with mixed fuel sources.

Because green power customers are paying a premium for a resource that does not rely on fossil fuels, they should be exempt from any fuel adjustment mechanisms that recover varying costs for these fuels. Few regulators have addressed this important issue.[113]

Customer-Provided Ancillary Services

Providing rates with time-varying energy, capacity, and ancillary service components could allow DG, energy efficiency, and DR programs to be compensated for newly recognized values that they bring to the system. Such compensation can provide additional revenue streams to these resources and make them more cost-effective for customers to deploy or utilize. It could also lead to a rebalancing of the grid investment portfolio in favor of decentralized solutions.

This is especially true in the case of ancillary services. In smart grid technology, an ancillary service supports the transmission of electricity from its generation site to the customer, may be reliability based, and may include load regulation, spinning reserves, non-spinning reserves, replacement reserves and voltage support, among other functions.[114]

For example, a smart grid's built-in communications infrastructure could enable the system operator to manage water heaters and distributed resources to provide reactive power, voltage support, and other ancillary services under some circumstances. The system operator would need to have operational control over DER in order to provide these services.[115] For this to happen with PV systems, the deployment of smart inverters would be required.[116] Germany requires solar inverters to perform certain functions, such as power ramping and volt/VAR control, which leads to more grid stability. EPRI is developing standards that set key functionalities for smart inverters to allow them to communicate with the grid.[117]

Pragmatically, it makes little sense to offer rates to residential and small commercial consumers that are so detailed that they include separate charges (or credits)

110 For a list of Green Pricing Programs by state, see: http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1.

111 Ibid. RECs, also known as renewable energy credits, green certificates, green tags, or tradable renewable certificates, represent the environmental attributes of the power produced from renewable energy projects and are sold separate from the associated commodity electricity.

112 Ibid.

113 For more information on green pricing, see the Center for Resource Solutions: http://www.resource-solutions.org/progs_bce.html.

114 FERC defines ancillary services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." See Hirst, E., and Kirby, B. (1996, February). Electric Power Ancillary Services, p. 1. Available at: http://www.consultkirby.com/files/con426_Ancillary_Services.pdf

115 Schwartz, L., and Sheaffer, P. (2011). *Is It Smart if It's Not Clean? Smart Grid, Consumer Energy Efficiency, and Distributed Generation, Part Two.* Montpelier, VT: Regulatory Assistance Project, p. 9. Available at: http://www.raponline.org/docs/RAP_Schwartz_SmartGrid_IsItSmart_PartTwo_2011_03.pdf

116 IEEE 1547 is the accepted engineering standard for distributed generation that interconnects to the grid. It was develop with an eye toward maintaining system safety and integrity, but not with an eye toward maximizing the value of DG to the system. For example, inverters meeting the IEEE 1547 standard are designed to separate the DG from load in the event the grid becomes unstable or unavailable, rather than continuing to supply energy to the customer and disconnecting from the grid altogether.

117 IEEE 1547.8, the latest update to the standard, is expected to allow inverter manufacturers to provide smart grid features.

for ancillary services. However, aggregators of demand response that can also provide ancillary services should be well-positioned to deal with detailed tariffs.

Most programs that reward customers for allowing grid-interactive control of loads for ancillary services are priced on a "virtual" rather than "measured" basis, providing a fixed monthly bill credit in exchange for allowing the utility or demand-response aggregator a defined level of control over the air conditioner, water heater, thermostat, or other controlled load. Many provide an "override" function allowing the customer to disengage participation when energy requirements are high, such as during a house party. These types of flexible arrangements greatly improve customer satisfaction and participation rates, and have been shown to have a very small impact on program performance.[118]

118 Ecofys water heater and space conditioning pilot for Bonneville Power Administration, 2012.

VI. Other Issues in Rate Design

Alternative Futures: Smart and Not-So-Smart

The Smart Future: Customers and Technology Unleashed

The smart future will see extensive use of technology to help consumers manage their energy costs, and utility pricing that enables these savings to occur. A mix of central generation, DG, energy efficiency, DR, and customer response to time-varying pricing will provide a rich mix of reliable, flexible, and environmentally benign sources to provide quality service at reasonable costs.

Consumers will increasingly have smart homes, as shown in Figure 14 (page 60), with smart appliances, water heaters, thermostats, and, in many cases, electric vehicles. These will receive information from the utility or grid operator on current conditions and prices, and respond intelligently to optimize comfort and service and minimize energy bills.

Utilities will use AMI for two-way communication, learning of conditions at individual nodes on the generation, transmission, and distribution system, and then dispatching a mix of supply resources and demand management to optimize costs, emissions, and reliability.

To achieve this smart future, regulators at various levels will have to take many discrete actions, including:

- Adopting time-varying and dynamic rate designs, with consumer education, shadow billing during a pre-deployment phase, a "hold harmless" provision the first year of implementation and excellent customer support throughout.
- Implementing some form of revenue regulation to ensure that utilities retain a reasonable opportunity to earn a fair return on investment on used and useful property serving the public and maintain access to capital at reasonable prices without erecting barriers to economic innovation.
- Implementing new state building energy codes to require home energy management systems in new homes (as most already do for commercial buildings).
- Requiring that new customer-sited generation include smart inverters, responding to provide reliability and ancillary services; enabling customer-sited batteries to not only provide service to the locations where they are installed, but to also be available to grid operators for system support; and incorporating solar orientation standards to optimize peak time production.
- Adopting appliance standards to require installation of control technologies in new major appliances such as refrigerators, water heaters, furnaces, heat pumps, air conditioners, dishwashers, clothes washers, and clothes dryers, so that they can automatically respond to changing prices.

Not-So-Smart Future

A number of electric utilities have proposed SFV rate designs in which all costs claimed to be "fixed costs" are recovered in a fixed monthly charge, and only those costs that are considered "variable" are recovered on a per-kilowatt-hour basis. While most have focused only on distribution costs, a few have gone further, proposing that the recovery of costs related to generation and transmission investment be included in monthly fixed charges.

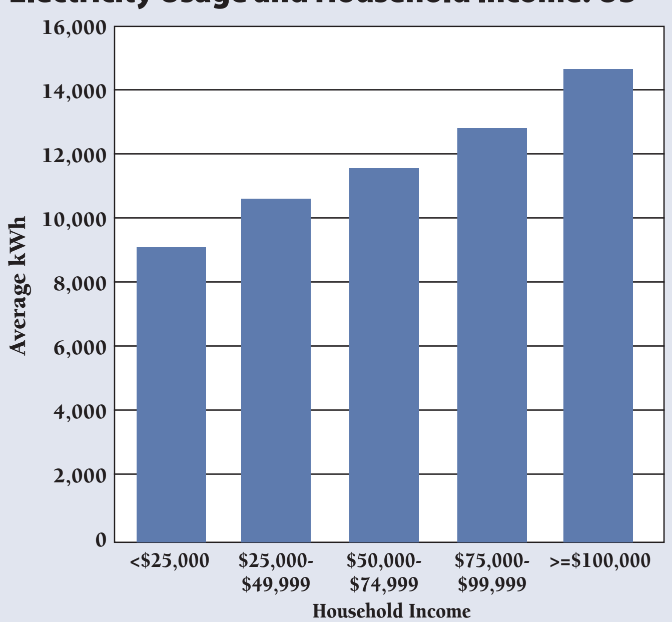
High fixed charges provide utilities with stable revenues and address their immediate concerns, but in doing so, they punish lower-usage customers, and discourage efficiency improvements and adoption of distributed renewables. Over time these charges can lead to an unnecessary increase in consumption or, in the event that distributed storage technologies become more affordable, promote customer grid defection. The adverse impacts on electric consumers and public policy goals for electricity regulation include:

- **Energy efficiency:** A higher fixed charge results in a lower per-kWh rate, which leads to disproportionate savings for larger dwellings and undermines customers' incentives to invest in efficiency improvements. For example, if a high-efficiency air conditioner will pay for itself in five years at 10 cents per kWh, that payback period doubles if the per-kWh rate drops to 5 cents per kWh due to implementation of a high fixed charge.

- **Competitive impact on renewables development:** A lower per kWh charge cuts into the potential savings from PV investments. Customers who do invest in PV are more likely to respond to a higher fixed charge (with which storage capacity would become more cost-competitive) by going totally off the grid, causing the utility to lose a customer permanently when it would be more efficient for both the customer and the grid for that customer to remain connected.
- **Low-income households:** An analysis prepared by the National Consumer Law Center shows that typical households below 150 percent of the federal poverty level use between 3 percent and 9 percent less electricity than the average of all households.[119] With a fixed rate design, most low-income customers' bills will rise despite their lower usage.
- **Apartment and urban dwellers:** As noted above, smaller units' bills rise under a higher fixed charge while larger dwellings' bills go down. This is the case despite the fact that residents of multi-family buildings tend, on a household basis, to have lower usage, and that it is actually cheaper to serve them.

Figure 16

Electricity Usage and Household Income: US [120]



- **Small-use residential consumers:** These customers are "less peaky" than higher-usage customers, and will generally benefit from time-varying pricing. While small-use customers have higher non-coincident peak relative to usage, their coincident peak is generally lower, primarily due to lower air-conditioning usage.[121]

The first of the principles of electricity pricing set out earlier notes that a customer should be able to connect to the grid for no more than the cost of adding that customer. The imposition of a fixed charge solely for the privilege of being a customer is not common in other economic sectors, from supermarkets to the travel industry that have similarly significant fixed costs to those of utilities. Allowing utilities to impose high fixed monthly charges is an exercise of monopoly power and impedes the longstanding goal of universal service in the United States. And the utility argument that fixed costs should be recovered via fixed charges is flawed with regard to both economic and accounting principles.

Utilities' concern about loss of revenue is fair, but an SFV model is probably the worst option available by which to address it. Alternatives include revenue regulation, or "decoupling," now adopted in more than half of US states; performance-based regulation; weather normalization; reserve accounts; demand charges; and connected load charges.

The regulatory and economic argument against SFV is explored in greater detail in Appendix D.

Addressing Revenue Erosion

A central theme from utilities is their concern over the decline in recovery of costs from customers who improve their energy efficiency or install their own generation — primarily PV. Improved efficiency reduces energy consumption and, therefore, utility sales across the board, while customer generation displaces utility-supplied energy. Most states have implemented NEM tariffs, which allow

119 There are exceptions to this low usage rate, typically associated with poorly insulated buildings and less efficient appliances and HVAC systems. Low-income weatherization and appliance rebate programs are helpful in this regard.

120 Adapted from John Howat of National Consumer Law Center, 2014.

121 Marcus, JBS Energy, 2015.

the DG customer to offset bills at the full retail rate. These implicitly assign a premium value to new renewable energy that is equal to the volumetric distribution price avoided by the NEM customer. Because those rates collect not just the incremental cost of generating energy delivered to the customer, but the costs of delivering that energy over the distribution and transmission systems, crediting customers with the full retail rate for the energy they produce causes a reduction in revenues that were designed to recover those costs. The rate design concepts discussed above do not address that issue. Rather, the rate designs discussed above focus on a fair and equitable allocation of costs based on the causation of those costs. Other solutions, however, are available, and this is a separate issue from revenue requirements.

Utility cost recovery and revenue stability can be addressed in many different ways, some desirable and some less desirable. Fixed charges, a higher allowed rate of return, incentive regulation, and revenue decoupling are four different approaches, all of which can serve to address the earnings volatility from sales variations. Fixed charges were previously discussed. The other approaches are discussed below.

Cost of Capital: A "Let the Capital Markets Do It" Approach

In states where revenue regulation mechanisms have not been deployed, regulators are effectively letting the capital markets set a higher rate of return for the utility. This leads to higher costs. The utility-allowed return on equity and equity capitalization ratio are the way that utilities are rewarded for taking the risks associated with serving customers at regulated prices. The return on equity is the percentage of shareholder profit allowed on the utility's plant investment, while the equity capitalization ratio is the percentage of capital in the business that is derived from shareholders (as opposed to bondholders, who get a fixed return).

If the utility enterprise is subject to earnings variations that are a part of the business, then the business is arguably riskier than a utility without such earnings variations. A utility exposed to earnings variations due to changes in customer usage may require a higher rate of return or equity ratio. Conversely, a utility with any sort of revenue stabilization mechanism (a fuel adjustment clause or a decoupling mechanism, as examples) would need a lower equity capitalization ratio, reducing the overall rate of return (but not the return on shareholder equity) and, in turn, educing the overall revenue requirement.

Either a higher return on equity or a higher equity ratio will increase the utility revenue requirement and ultimately lead to higher rates for customers. Thus this laissez-faire approach certainly results in higher costs to consumers over time.

Incentive Regulation: An "Incentivize Management" Approach

Incentive regulation, or performance-based ratemaking (PBR), is a large topic well beyond the scope of this rate design report. It is addressed in great detail in several other RAP publications.[122] However, PBR is one way to address the revenue loss that utilities experience if customer sales decline. If the regulator sets the achievement of a defined level of sales reduction from energy efficiency as a goal, and provides a financial reward to the utility for achieving that, the regulator can make up the lost earnings that the utility experiences. Similarly, if the regulator sets a specific goal for deployment of renewable generation, and provides a financial reward to the utility for achieving that, the regulator can provide for recovery of lost earnings that the utility experiences.

The challenge in PBR is to set the objectives for the utility to be achievable but challenging, and to set the rewards to be ample but not excessive. This is complex, but can address some or all of the lost revenue challenge for utilities if properly developed and monitored and can change the utility culture toward performance that is more in line with public policy goals. PBR does require significant effort on the part of regulators to implement and monitor and can impose additional expenses on stakeholders involved in utility rate cases.

122 See Lazar, J. (2014). *Performance-Based Regulation for EU Distribution System Operators.* Brussels: Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/7332; and Weston et al. (2000). *Performance Based Regulation for Distribution Utilities.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/docs/RAP_PerformanceBasedRegulationforDistributionUtilities_2000_12.pdf

Revenue Regulation and Decoupling: A "Passive Auto-Pilot" Approach[123]

Revenue-based regulation, or "decoupling," is widely used throughout the United States to insulate gas and electric utilities from revenue impacts due to sales variations. The essence of revenue regulation is that the utility regulator sets an allowed revenue level, and then makes periodic small adjustment to rates to ensure that allowed revenue is achieved, independent of changes in units (kW and kWh) sold. Revenue regulation does not assure a given profit level, only the allowed revenue recovery.

Because revenue regulation removes utility management's incentive to increase sales, most of the electric revenue regulation mechanisms in the United States were established to facilitate more active utility involvement in energy-efficiency programs that by their nature are intended to reduce sales. The success of those programs in California, Oregon, Washington, and other states is widely attributed to the removal of the shareholder earnings impact of lower sales.[124]

The essence of revenue regulation is that changes in sales volumes do not result in changes in revenue. This does not always mean a rate increase, because sales sometimes rise above the levels anticipated in general rate proceedings. For example, in a year with a hotter summer or colder winter, the utility would reduce rates. In the context of DG and EV, this means that the "excess revenues" from additional sales to electric vehicles may offset the "lost revenues" due to solar or energy conservation investments.

One benefit of revenue regulation is that the utility normally receives a "formula" to reflect higher costs, such as a "revenue per customer" allowance. These do tend to lead to very small annual increases in revenues. Whether prices rise depends on whether average consumption by customers is rising or declining as the number of customers change. The use of a revenue per customer adjustment may allow the utility to maintain a total revenue trajectory sufficient to delay its next general rate case, saving both the utility and the regulator the significant costs that rate cases involve.

Revenue regulation has critics, primarily state utility consumer advocates and some low-income advocates. Their concern is that these mechanisms result in annual increases, and that declining costs in some areas are not offset against rising costs in other areas, as occurs in a general rate case. A well-structured mechanism can address these concerns. It should be noted also that the alternatives to revenue regulation, such as SFV, may have even more serious adverse impacts on these constituencies.

A well-designed revenue regulation framework is the best option to address utility revenue attrition that energy efficiency or renewable energy deployment may cause, for the following reasons:

- The rates can remain volumetric, preserving incentives for efficient use of energy and for deployment of renewable resources;
- Customer bills remain very predictable, and linked to usage so customers can control the size of their bills;
- Small-use customers are not disproportionately affected, as they are with high fixed charges;
- Utilities, regulators, and intervenors avoid the cost of annual rate cases;
- If actual revenues exceed authorized revenues, customers can see a rate decrease;
- The framework provides transparency for customers to know what the level of revenues are; without decoupling, utilities who do not seek rate increases for long stretches may not be filing because their earnings are higher than authorized; and
- A periodic general rate case review of all costs and revenues ensures that any imbalance between costs and revenues does not persist. A three- to five-year periodic review is typical.

There is no silver bullet to address the legitimate concerns of all interests. The evidence, however, is that high fixed charges have the most adverse impacts on consumers, the environment, the economy, and society. Good rate design addresses the legitimate concerns of all major interests, provides a framework for stable regulation

123 For more information see: Lazar, J., Weston, R., and Shirley, W. (2011). *Revenue Regulation and Decoupling.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/902

124 See Morgan, P. (2012). *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations. Graceful Systems.* Available at: http://aceee.org/collaborative-report/decade-of-decoupling; and Howat, J., and Cavanagh, R. (2012). Finding Common Ground Between Consumer and Environmental Advocates. *Electricity Policy.* Available at: http://switchboard.nrdc.org/blogs/rcavanagh/Ralph%20Cavanagh%20and%20John%20Howat_Final.pdf

of utilities, and enables the growth of renewable energy and energy efficiency to meet electricity requirements.

Bill Simplification

In many states, the utility bill has become a rather dense tangle of line items that represent, in many cases, a long history of policy initiatives and regulatory decisions. In many cases, they are a kind of tally of the rate-case battles won and lost by advocates and utilities, a catalogue of special charges and "trackers" dealing with particularly knotty investment and expenditure requirements. The accumulated result is often a bill that consumers find difficult to navigate. A customer's electric bill typically consists of a monthly customer charge, one or more usage blocks (or time-of-use periods), and as many as ten surcharges, credits, and taxes added to these usage-related prices.

Some utilities present all of the detail on the bill, and it can be confusing and overwhelming to the consumer. Table 11 shows an example of how the customer's bill may look with all of the detail. To the extent that line items can be eliminated or combined, consumer confusion is likely to be reduced.

Alternatively, all of the detail can be provided, but the bill should "roll-up" all of the rate components, adjustments, taxes, surcharges, and credits into an "effective" rate that the consumer pays. Table 11 shows what the customer actually pays in each usage-related rate component and better informs customers what they will pay if they use more electricity, or save if they use less electricity.

Utilities should be required to display the "effective" rate to customers, including all surcharges, credits, and taxes in the effective price, so consumers can measure the value of investing in energy efficiency or other measures that reduce (or increase) their electricity consumption.

Table 11

Customer Adjustments

Example of an electric bill that lists all adjustments to a customer's bill.

Your Usage: 1,266 kWh

Base Rate	Rate	Usage	Amount
Customer Charge	$5.00	1	$5.00
First 500 kWh	$0.05000	500	$25.00
Next 500 kWh	$0.10000	500	$50.00
Over 1,000 kWh	$0.15000	266	$39.90
Fuel Adjustment Charge	$0.01230	1,266	$15.57
Infrastructure Tracker	$0.00234	1,266	$2.96
Decoupling Adjustment	$(0.00057)	1,266	$(0.72)
Conservation Program Charge	$0.00123	1,266	$1.56
Nuclear Decommissioning	$0.00037	1,266	$0.47
Subtotal:	$139.74		
State Tax	5%		$6.99
City Tax	6%		$8.80
Total Due			**$155.53**

The rate above, with all of the surcharges, credits, and taxes applied to each of the usage-related components of the rate design.

Base Rate	Rate	Usage	Amount
Customer Charge	$5.56500	1	$ 5.56
First 500 kWh	$0.07309	500	$ 36.55
Next 500 kWh	$0.12874	500	$ 64.37
Over 1,000 kWh	$0.18439	266	$ 49.05
Total Due			**$155.53**

Source: Lazar et al, *Revenue Regulation and Decoupling,* 2011.

Customer Revenue Responsibilities

As mentioned earlier, as customers utilize greater energy efficiency and deploy more PV, the reductions in their bills can have the effect of allocating greater cost recovery responsibility to other customers. This is often described as a cross-subsidy. However, this is an unfair characterization. In fact, the system for allocating costs among customers and customer classes has always been a dynamic one that reflects the changing characteristics of all customers over time. The fact that relative cost responsibility changes from one time period to another is not conclusive of the existence of a subsidy. This is especially true given that there is no single "correct" method of allocating costs and, even if there were one, it would by necessity have to accommodate changing consumption patterns over time. It is also unfair because the direct customer investment is replacing capital and other costs that the utility would otherwise have to incur and charge to all customers. That said, this is an important issue that regulators will face as energy efficiency, customer-owned generation, and storage become more prevalent.

Changes in Customer Characteristics and Class Assignments

"Smart"-Enabled Customers

Even if all customers in a given class (e.g., residential or small commercial) are equipped with smart meters, they may not all be in the same position to deploy smart appliances or be able to finance energy efficiency or distributed generation in their homes or businesses — especially those who rent, rather than own, their homes or business premises. This may present a challenge for regulators in terms of assuring a sense of fairness among otherwise similarly situated customers. Ideally, the presence of additional smart technologies will actually lower costs for all customers, even those who do not have access to all of the smart bells and whistles. Regulators will need to take care in rate design to assure that all customers share in the benefits that industry changes will bring and that no customer group is left out of the mix.

Once past these issues, regulators should focus on rate design approaches that will maximize the value of smart technologies for customers who can take advantage of them. This includes all smart-metered customers, but also those with smart appliances and smart buildings. Without appropriate rate design, the value of smart technologies to those customers and to the electric system generally will not be realized.

DG Customers

As power producers, DG customers represent a special group of customers. Going forward, if these customers are subject to time-varying rates, they will pay for all services they receive from the utility whether at on-peak or off-peak times, and be credited for the time-differentiated value of the power they supply, also whether at on-peak or off-peak times. If they directly bear the cost of their connection to the grid (service drop, meter, billing), and if grid costs are recovered appropriately in time-varying rates, they will pay the full cost of any service they receive from the utility. The rate design principles set forth at the beginning of this paper are crafted with this in mind. The position advocated by some, that all customers have an equal cost responsibility for grid costs regardless of usage levels, is inconsistent with how the cost of infrastructure is recovered in competitive industries, and a key purpose of regulation is to enforce the pricing discipline that competition normally provides.

Non-DG Customers

Customers who have not deployed their own generation systems (non-DG customers) will likely see some increase in the prices they pay for non-generation-related costs as additional customer-sited DG comes onto the grid if this results in a sales decline. This effect will be most notable with respect to distribution costs. To the extent DG and other customer resources are replacing utility capital, overall costs in utility rates may decline.

If the rate design for DG customers is properly implemented, that is, if customers are not unduly rewarded for deploying DG, the collateral benefits of DG — such as reduced line losses, deferred and avoided distribution investments, and the potential for overall reductions in the price of generation — then non-DG customers will see equitable prices for energy delivered to their meters. Regulators should account for these benefits when considering the impact of customer-owned DG on non-DG customers.

Departing Customers

Customers who install their own generation and go "off grid" deliver a one-time decline in system costs, to the extent that system investments are deferred or avoided by their absence. However, they do not deliver many of the benefits that grid-connected DG customers provide, because they are not injecting energy into the system at any time. Thus, reduced losses, reduced wear and tear on equipment and other savings derived from their presence are not present to benefit other customers. As discussed, regulators should avoid rate design strategies that encourage customers to depart the system when their continued presence would be a net benefit to everyone.

VII. Conclusions

The future of the electric sector will likely include storage, microgrids, EVs, and more DER. Homes and businesses will use electricity more efficiently. As entrepreneurs continue to study consumer behavior and a greater understanding of the operational characteristics of the electric system is revealed through smart technologies, new technologies and applications will undoubtedly develop. Change will likely be constant and subject to iterations, refinements, and new technologies. How regulators respond to these changes will matter greatly in terms of the expansion of new frontiers or perpetuation of the status quo.

Rate design will be an important driver of the success of the utility of the future at assisting with the transition to a clean power system. Utilities, customers, and third-party service providers will need the tools to manage the grid as efficiently as possible. Regulators will need to assure that benefits and costs are fairly allocated. Knowledge of and accuracy in pricing can reward customers for energy usage behavior that contributes to the reduction, rather than increase, in utility system costs.

For DG customers specifically, the price they pay or receive for electricity they either consume or provide to the grid respectively will matter greatly in terms of encouraging or discouraging the growth of this industry. Bidirectional rates with TOU pricing may offer one of the best solutions for this segment of the market. Under this rate design, the DG customer pays the full retail rate for any power consumed, just like any other customer. This customer is then compensated based on the same time periods, either using the retail rate or on a value basis. That value can be based on an analysis of the contribution of DG to the grid and can be set independently by a state public service commission.

Whether as a separate rate or as a proxy, the commission can use the same retail generation TOU rate used for charging customers, applied to the price at the time the DG produces power to the grid. Other benefits can be layered on to reflect additional value that a DG might provide in terms of location or other attributes.

Utility rate designs will have to more appropriately reflect the cost of electricity provided by the utility and the benefits that are provided to the utility system by customers. With more innovative technologies being developed and offered by utilities and third-party vendors (such as smart appliances able to respond to grid pricing signals), the need to become more geographically, temporally, and functionally granular and more precise with pricing will expand. While rates today are typically flat or inclining, these rates only send price signals about consumption and conservation. Smart rate designs will need to address not only the amount consumed but also when it is consumed and its impact on costs and other customers.

A small number of utilities offer some kind of dynamically priced rate to residential customers, whether it be a TOU rate or a PTR. As of this publication, most dynamic residential rates are offered only on a pilot basis. Some studies like that conducted by SMUD and OG&E have produced good data demonstrating the potential benefits of TOU rates for residential (including low-income) customers and the utility system as a whole.

However, for policymakers to move forward in the direction of TOU pricing on a larger scale, customer education will be important to empower informed decisions about energy use. Customers will also need to see the value of TOU rates and should be given a choice among rate options. Providing customers with a shadow bill that compares their monthly energy bill under a flat or inclining rate with what it would have been under a TOU rate is a good tool to educate customers. Shadow bills not only educate customers as to how TOU rates work, but they also offer an opportunity for customers to analyze how that rate affects them personally and learn how they can reduce their electric bills.

Where a DG resource is located is an important factor in determining its value to the customer and to the electric system as a whole. DG that is strategically located at a load center can bolster voltage support and alleviate a utility's obligation to provide additional transmission and distribution facilities, deferring or avoiding the associated costs. Rate design that rewards customers for deploying those resources helps make the economic case to build.

Aging grid infrastructure is a nationwide problem that will cost billions of dollars to remedy, and creative solutions that combine DG, storage, advanced metering, and other technologies should be increasingly deployed to help minimize those costs.

In addition to recognizing locational benefits in pricing, good rate design recognizes the attributes that a customer can provide in terms of energy, capacity, and ancillary services. Recognizing these attributes through appropriate price signals will allow DG, DR, and energy efficiency to access new markets that can provide additional revenue streams to improve the economics of those resources for the end-use customer. It can also lead to a rebalancing of the centralized grid portfolio in favor of a mix of flexible generation and decentralized solutions. This could become increasingly more important in the wake of concerns regarding cybersecurity and the threat of massive blackouts.

A number of rate designs have been discussed here that explore the pros and cons of those rate structures that are already frequently used as well as those that are just emerging. Viewed as a quick fix to lost revenues associated with customer engagement in energy solutions, SFV rates with high monthly fixed charges are increasingly being proposed by utilities. SFV is not a step forward, but a step backward. With new technologies becoming more prevalent, it will be important that rate designs reflect actual future changes in system costs and benefits associated with customer usage in order to properly align responsibility for costs, compensate for benefits, and send the correct price signals to all customers. SFV is the antithesis of this, creating a simplistic one-size-fits-all rate that does not align cost to cost causation and has adverse consequences for urban, multi-family, low-income, and low-use customers as well as those who invest in energy efficiency, demand response, and distributed generation. By de-linking customer use from the customer's bill, SFV encourages wasteful consumption and sends misleading, incomplete price signals to the consumer.

The role of regulation in power sector transformation will be to develop pathways that lead to smarter solutions that optimize the value of interconnection and two-way communication for the customer and the grid. Many of these solutions will be market-driven.

Utilities have a long history of operating as a monopoly. As technology and innovation encroach on what was their exclusive domain, they will need to adapt and, to some degree, reinvent themselves. As such, power sector transformation will need to incorporate new tools to address these changes. Rate design will be an important element.

However, there are other instruments available to prepare for and move with these changes. They include PBR and integrated distribution grid planning (IDGP), among other tools, to help protect the financial integrity of the grid while assuring that rates are fair and affordable for all customers. PBR, for example, can help change utility motivation and culture by rewarding the utility, not through a return on investments but through behavioral changes such as expanding energy efficiency and DR programs, encouraging DG, making the grid more reliable, improving customer service, and increasing operating efficiency.

IDGP, just emerging in California and New York, can provide valuable information to regulators as to what is needed to keep the grid secure. Like an IRP, it can identify least-cost solutions that could include the strategic location of DG or the implementation of demand response and energy efficiency at a load site or some combination thereof.

The speed at which change takes place will vary from jurisdiction to jurisdiction and will be influenced by what customers want as well as utility culture. Regulators will have an important role to play in overseeing this transformation. There will be many pilots and projects implemented, including microgrids; storage via electric vehicle batteries or other sources; and energy efficiency programs from whole-house home performance programs to using smart, two-way communication technologies to manage water heaters and distributed generation in order to provide voltage support, reactive power and other ancillary services. Learning from pilots and experiments is a new duty for regulators, and will require additional resources.

A critical component of unlocking the real value of these changes will be the utilization of time-differentiated pricing and the connection of customer and system operator level technologies that will allow a more dynamic interaction between the two. Rather than the traditional model of simply building the necessary supply-side resources to meet an unmitigated demand for energy, smart grids, meters, homes, buildings, and appliances will need to become a more interconnected whole that yields a more optimum cost and engineering solution than previously experienced.

In the interim transition to this future, regulators should strive to avoid expensive mistakes based on defense of the legacy structure of the industry. In their stead, regulators will need to focus on identifying costs and benefits of alternative strategies and seek to maximize the net value to customers and society.

Guide to Appendices

These accompaniments to the main paper can be found in our online library at the links below.

Appendix A: Dividing the Pie: Cost Allocation, the First Step in the Rate Design Process

http://www.raponline.org/document/download/id/7766

Cost allocation among customer classes, commonly called the "cost of service" study, is the first step in the rate design process. In the past, cost allocation followed historically evolved methods in each state, with costs divided into "customer," "demand," and "energy" costs. With the evolution of demand response as the lowest-cost peak capacity resource, the ability to measure usage for all classes by time of day, and the use of smart meters not only for customer billing but also for energy conservation and peak load management purposes, these historical methodologies require fundamental revision.

In general, only customer-specific costs, such as billing and collection, are properly considered customer-related costs. Most grid costs and power supply costs are best treated as time-varying volumetric costs, not as simple "demand" or "energy" costs.

Appendix A provides a greater discussion of these issues. A significantly more in-depth publication is tentatively planned in 2016 and will address cost allocation.

Appendix B: Rate Design for Vertically Integrated Utilities: A Brief Overview

http://www.raponline.org/document/download/id/7767

Most electric utilities in the United States have had relatively simple rate designs for residential consumers. These consist, generally, of a monthly fixed customer charge that collects customer-specific costs like billing and collection, and one or more energy blocks that collect all other costs. Some utilities have seasonal rates, some have inclining block rates, and many offer optional time-varying rates. A few have moved to include distribution costs within the monthly fixed customer charge, while others use a minimum bill form, rather than a customer charge, to collect some revenue from very low-use consumers.

Appendix B provides a greater discussion of current rate designs. In addition, detail can be found in these previous publications on this topic:

- Distribution System Cost Methodologies for Distributed Generation (2001)
- Pricing Do's and Don'ts (2011)
- Time-Varying and Dynamic Pricing (2012)
- Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed (2013)
- Designing Distributed Generation Tariffs Fairly (2014)

Appendix C: Restructured States, Retail Competition, and Market-Based Generation Rates

http://www.raponline.org/document/download/id/7767

In states that have restructured, the power or generation portion of a customer's bill is usually not provided by the incumbent utility. The distribution utility in some restructured states can acquire the power requirements for the customer, called the Standard Service Offer (SSO) or Default Service. The SSO is typically competitively procured by the distribution utility in an auction process.

In states that allow retail competition, the customer can bypass the SSO and directly select a competitive retail energy supplier from a list of certified suppliers to provide his/her power requirements. Customers can also join governmental or community aggregations to attain supplier price discounts. The competitive retail suppliers may offer rate designs for power supply that differ significantly from the SSO rate design.

The evolution of wholesale power markets has led to the development of businesses that aggregate the demand management power attributes of one or many customers and offer this resource back into the energy and capacity market at a price.

Appendix C provides a greater discussion of these topics.

Appendix D: Issues Involving Straight Fixed Variable Rate Design

http://www.raponline.org/document/download/id/7771

Utilities in some parts of the United States are seeking changes to rate design that sharply increase monthly fixed charges, with offsetting reductions to the per-unit price for electricity. This approach deviates from long-established rate design principles holding that only customer-specific costs — those that actually change with the number of customers served — properly belong in fixed monthly fees. They mistakenly use the notion that short-run so-called "fixed" costs should be recovered through fixed charges. As a result, they do not appropriately reflect long-term costs, all of which are variable. The effect of this type of rate design is to sharply increase bills for most apartment dwellers, urban consumers, highly efficient homes, and customers with DG systems installed, while benefitting high-use larger homes and rural customers with above-average distribution costs. While these rates do provide revenue stability for utilities, there are more appropriate and economically sound approaches that should be used in their stead. The use of these rates risks placing consumers on an ill-advised consumption path, while putting the very viability of the industry in question.

Appendix D discusses how the future is better served by reflecting costs that are not individual customer-specific — including nearly all distribution system costs — in time-varying rates for usage that is beneficial to the public interest.

Glossary

Adjusted Test Year
A utility's investment, expense, and sales information used to allocate costs among customer classes and for setting prices for each customer class. Adjustments to historical data are made for known and measurable changes to reflect the operating and financial conditions the utility is expected to face when new rates are implemented.
See Also: "Test Year," "Historical Test Year."

Adjustment Clause
A rate adjustment mechanism, implemented on a recurring and ongoing basis, to recover changes in expenses or capital expenditures that occur between rate cases. The most common adjustment clause is the fuel and purchased power adjustment clause, which tracks changes in fuel costs and costs of purchased power. Some utilities have weather normalization adjustment clauses, which correct for abnormal weather conditions.
See Also: "Tracker," "Weather Normalization" and "Lost Revenue Adjustment Mechanism."

Advanced Metering Infrastructure (AMI)
A combination of smart meters, communication systems, system control and data acquisition systems and meter data management systems. Together, these allow for metering of customer energy usage with high temporal granularity; the communication of that information back to the utility and, optionally, to the customer; and the potential for direct end-use control in response to real-time cost variations and system reliability conditions. AMI is an integral part of the smart grid concept.
See Also: "Smart Meter," "Supervisory Control and Data Acquisition," "Meter Data Management System," "Smart Appliance," "Smart Technology," and "Smart Grid."

Aggregation
Bundling of multiple customers or loads to achieve economies of scale in energy markets. Aggregation also takes advantage of the diversity of loads among multiple customers and enables companies to offer price risk management services to those customers.

Aggregator
A company that offers aggregation services and products.

Allocation
The assignment of utility costs to customers, customer groups, or unbundled services based on cost causation principles.

Allowed Rate of Return
The weighted cost of capital used by the regulator to determine a utility's revenue requirement.
See Also: "Cost of Capital," "Weighted Cost of Capital," "Cost of Debt" and "Revenue Requirement."

Ancillary Service
One of a set of services offered in and demanded by system operators that generally address system reliability and operational requirements. Ancillary services include such items as voltage control and support, reactive power, harmonic control, frequency control, spinning reserves and standby power. The Federal Energy Regulatory Commission defines ancillary services as those services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

Appliance
Any device that consumes electricity. Appliances includes lights, motors, water heaters, and electronics, as well as typical household devices such as washers, dryers, dishwashers, computers and televisions.
See Also: "Smart Appliance."

Area Regulation
Area regulation is one of the ancillary services for which storage may be especially well-suited. It involves managing "interchange flows with other control areas to match closely the scheduled interchange flows" and moment to moment variations in demand within the control area. In more basic terms, area regulation is used to reconcile momentary differences between supply and demand. That is, at any given moment, the amount of electric supply capacity that is operating may exceed or may be less than load.

Avoided Cost
The cost of providing additional power, including the cost of the next power plant a utility would have to build to meet growing demand, plus the costs of augmenting reliability reserves, additional transmission and distribution facilities, environmental costs, and line losses associated with delivering that power.

Baseline Rate
A rate that allows all customers to buy a set allowance of energy at lower rates than additional usage.

Baseload Generation/Baseload Units/ Baseload Capacity/Baseload Resources
Electricity generating units which are most economically run for extended hours. Baseload generation is generally characterized by low short-run marginal costs (i.e., fuel) and, usually, high capital costs. Baseload resources are the "first" units dispatched to serve load. Baseload units often have operating constraints which make it difficult from an engineering or economic viewpoint to cycle their output up and down to match changes in load. Typical baseload units include coal-fired and nuclear-fueled steam generators.

Capacity
The ability to generate, transport, process, or utilize power. Capacity is measured in watts, usually expressed as kilowatts (kW) or megawatts (MW). Generators have rated capacities that describe the output of the generator at its bus bar when operated at its maximum output at a standard ambient air temperature and altitude. The capacity of some types of generation (e.g., combustion turbines) varies inversely with ambient air temperature and altitude. Transmission and distribution circuits have rated capacities that describe the maximum amount of power that can be transported across them and vary inversely with ambient air temperature. Transformers and substations have rated capacities that describe the amount of power that can be moved through their transformation systems and switching equipment. Generally, the capacity of any portion of the grid declines as temperatures rise. In some systems, components are said to be "thermally limited," or limited by their physical capability to withstand the heat produced by the electric current. In other systems, notably in the Western Interconnection, the physical configuration of the system (long transmission lines and generation that is extremely remote from load centers) presents stability issues with respect to frequency, voltage and other parameters, in which case the capacity of the system is said to be "stability limited."
See Also: "Circuit."

Capacity Firming
The use of low-cost options including demand response, interruptibility, or emergency generators to supply capacity when other generating resources, including variable renewable energy resources, are not supplying energy to the grid. The fixed costs of firming resources are generally much smaller than the cost of additional dispatchable generation capacity.

Central Station/Central-Station Power Supply
A generating unit that is not located at or near customer load. The term is usually used to denote generators that require high-voltage transmission, often over long distances, to deliver power from the generator to the load centers.
See Also: "Customer-Sited Generation" and "Distributed Generation."

Circuit
Circuit generally refers to a wire that conducts electricity from one point to another. At the distribution level, multiple customers may be served by a single circuit that runs from a local substation or transformer to those customers. At the transmission level, the term "circuit" may also describe a pathway along which energy is transported or the number of conductors strung along that pathway.
See Also: "Distribution," "Substation," and "Transformer."

Class Peak Demand
The combined demand of all customers in a single rate class at the point in time when that demand is at its maximum, usually during a specific historical or forecast year, during a specific month or a specific hour of the day. Class peak demands do not necessarily — indeed, usually do not — coincide with the system peak demand. Residential classes tend to experience their daily peak demand in the late afternoon and early evening. Commercial customers tend to experience their daily peak demand in early to mid-afternoon. Industrial customers may experience their peak demand at virtually any hour of the day, depending upon their internal processes and their ability to manage multiple types of loads.
See Also: "Peak Demand," "System Peak Demand," "Coincident Peak Demand," and "Non-Coincident Peak Demand."

Classification
A step in an embedded cost of service study in which costs are separated into demand-related, energy-related, joint, and customer-related categories.

Cogeneration/Combined Heat and Power (CHP)
A method of producing power in conjunction with providing process heat to an industry, or space and/or water heat to buildings.

Coincident Peak Demand
The combined demand of a single customer or multiple customers at a specific point in time or circumstance, relative to the peak demand of the system, where system can refer to the aggregate load of single utility or of multiple utilities in a geographic zone or interconnection or some part thereof.
See Also: "Peak Demand," "System Peak Demand," "Class Peak Demand," and "Non-Coincident Peak Demand."

Community Aggregation
The bundling of multiple customers into a single purchasing block, usually at a municipal or other local governmental level, but potentially including local microgrid or residential or commercial development aggregations.

Competitive Retail Electricity Supplier (CRES)
In states where retail competition is allowed, the party contracting with the customer to provide electric or other services.

Congestion
A condition that occurs when insufficient transfer capacity is available to implement all the preferred schedules for electricity transmission simultaneously. Congestion prevents the economic dispatch of electric energy from power sources.

Connected Load Charge
A rate design in which customers pay a fixed charge based on the capacity of their service interconnection. The bigger the capacity of the interconnection, the greater the fixed charge. Connected load charges are a way of allocating and recovering the costs of, primarily, distribution system costs.

Connection Charge
An amount to be paid by a customer to the utility, in a lump sum or in installments, for connecting the customer's facilities to the supplier's facilities.

Conservation Voltage Reduction (CVR)
Using smart distribution grid sensors and controls to ensure that distribution voltages are maintained at a uniform level just above the minimum level required by electrical equipment. Sometimes called Conservation Voltage Regulation.

Cost Allocation
Division of a utility's cost of service among its customer classes. Cost allocation is an integral part of a utility's cost of service study.
See Also: "Cost of Service Study."

Cost of Capital
The costs a utility incurs borrowing money and, in the case of for-profit utilities, issuing equity to shareholders. Cost of capital includes the interest paid on debt and what is commonly thought of as the utility's profit. For purposes of regulation, the utility's profit is considered a cost because it represents the return on investment which shareholders demand to induce them to purchase the company's stock.
See Also: "Cost of Equity," "Cost of Debt," "Weighted Cost of Capital" and "Rate of Return."

Cost of Debt
The average interest rate on all debt issued by the utility, including bonds, notes, and other instruments. In some regulatory proceedings, this is separated into long-term debt (over 1 year to maturity) and short-term debt.

Cost of Equity
The rate of return necessary for a utility to attract equity capital, as determined by the regulator using one of several different methodologies.

Cost of Service Study (COSS)
A mathematical allocation of the utility's revenue requirement among customer classes, based on the number of customers, kilowatt-hours of consumption, and capacity requirements for each class. Some states use embedded cost studies looking at historical costs, while others use marginal cost studies looking at prospective costs. There are as many ways of doing cost of service studies as there are analysts performing these studies, and the assumptions made have a significant impact on the results calculated.
See also: "Embedded Cost" and "Marginal Cost."

Criteria Pollutant/Criteria Pollution Emission
The United States Environmental Protection Agency (EPA) is mainly concerned with emissions which are or could be harmful to people. EPA calls this set of principal air pollutants criteria pollutants. The criteria pollutants are carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM), and sulfur dioxide (SO_2). These are distinct from carbon dioxide (CO_2) pollution.

Critical Peak Pricing/Critical Period Pricing (CPP)
A rate design in which a limited number of hours or other periods of the year are declared by the utility, usually on a day-ahead basis, to be critical peak demand periods. when system reliability is at risk due to generation or transmission equipment failures, and during these times, prices charged to the customer will be extraordinarily high. The purpose of critical peak pricing is to reduce demand during the small number of hours of the year when generation costs are at their highest.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Peak Time Rebate," "Seasonal Rate" and "Straight-Fixed/Variable Rate."

Curtailment/Curtailment Service
A reduction in customer load in response to prices or when system reliability is threatened. Price-responsive curtailment is made possible through specific curtailment programs or when offered in competitive markets as a resource. Utilities typically have a curtailment plan that can be implemented if system reliability is threatened. Critical loads, such as hospitals, police stations and fire stations, may be given high priority and be last to be curtailed in an emergency, while non-critical loads, such as some industrial and commercial customers, may be the first to be curtailed. Many customers enter into specific contracts specifying their protection from or willingness to be curtailed. They may also have interruptible tariffs which, in return for price discount, allow the utility to curtail service on short notice.
See Also: "Curtailment Service Provider."

Curtailment Service Provider

A party that contracts with retail customers to procure the right to curtail their service under certain conditions (based on market prices or system reliability conditions), then sells that curtailment right to a utility as a service or offers it as a service in a competitive market, where it is treated as an energy resource.
See Also: "Curtailment/Curtailment Service."

Customer Charge/Basic Charge/Service Charge

A fixed charge to customers each billing period, typically to cover metering, meter reading, and billing costs that do not vary with size or usage.

Customer Choice

The ability of a customer to choose an energy supplier. Customer choice is available in a limited number of jurisdictions where retail competition is allowed. In most instances, the choice is limited to generation supply. The delivery of that supply to the customer is typically still provided by the local monopoly utility.

Customer Class

A collection of customers sharing common usage or interconnection characteristics. Common customer classes include residential (sometimes called household), small commercial, large commercial, small industrial, large industrial, agriculture (primary irrigation pumping), mining, and municipal lighting (streetlights and traffic signals). All customers within a class are typically charged the same rates, although some classes may be broken down into subclasses based on the nature of their loads (electric vehicle charging or solar photovoltaic generation customers may be placed in their own subclass), the capacity of their interconnection (e.g., the size of commercial or residential service panel) or the voltage at which they receive service.

Customer-Related Cost

Costs that vary directly with the number of customers. Customer-related costs include a portion of metering, billing, and customer service costs, but do not include distribution system, transmission, or generation costs.

Customer-Sited Generation

Generation located at a customer's site. Customer-sited generation includes residential solar photovoltaic, as well as backup generating units such as are common in hospitals, hotels, and critical government facilities. Customer-sited generation is a form of distributed generation. Most customer-sited generation is "behind the meter," meaning it operates on the customer's side of the utility's meter. But it may be interconnected to the grid, which requires it to operate synchronously with the electric system and makes it subject to certain operational and equipment requirements usually specified in an interconnection agreement or tariff. Output from customer-sited renewable generation is often accounted for under net energy metering tariffs.
See Also: "Distributed Generation" and "Net Energy Metering."

Declining Block Rate

A form of rate design in which blocks of energy usage have declining prices as the amount of usage increases. Declining block rates have largely fallen out of favor because they reward greater energy usage by the customer and do not properly reflect the increased costs associated with new resources needed to supply greater usage. They also undermine the economics of energy efficiency and renewable energy by reducing the savings a customer can achieve by reducing energy purchases from the utility.
See Also: "Flat Rate," "Inclining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Peak-Time Rebate," "Seasonal Rate," and "Straight-Fixed/Variable Rate."

Decoupling

A form of revenue regulation in which the utility's nonvariable costs are recovered through a prescribed level of revenues, regardless of the sales volume experienced by the utility. Under traditional regulation, regulators determine a set of prices (customer charge, energy charge, demand charge, etc.) that remain constant between rate cases and are based on adjusted test year sales volumes, regardless of the actual sales volume experienced by the utility. As a result, actual revenues, and implicitly utility profits, will rise or fall from expected levels as sale volumes increase or decrease. Decoupling fixes the amount of revenue to be collected and allows the price charged to float up or down between rate cases to compensate for variations in sales volume in order to maintain the set revenue level. The target revenue is sometimes allowed to increase between rate cases on the basis of a fixed inflator or on the basis of the number of customers served. The latter approach is known as "revenue-per-customer decoupling." Full decoupling also has the effect of weather-normalizing revenues — that is, the effects of abnormal weather are removed so as to assure recovery of the target revenues. Decoupling was developed as a way to eliminate utility management's incentive to increase profits by increasing sales and the converse incentive to undermine end-use energy efficiency and customer-sited generation, both of which reduce sales volume. Decoupling has typically been implemented in conjunction with regulator-required, utility-sponsored energy efficiency programs.
See Also: "Lost Revenue Adjustment Mechanism," "Revenue Regulation," and "Weather Normalization."

Default Rate/Default Service/Standard Service Offer (SSO)

The rate schedule a customer will pay if a different rate option is not affirmatively chosen in a competitive or restructured framework. When new rate designs are offered or experimental rates are implemented, it is typical for the utility to either use an opt-in or opt-out approach for determining what rate a customer will pay. In opt-in cases, the default rate is usually the same rate the customer would have paid before the new rate design was made available. In opt-out cases, the default rate is the rate associated with the new rate design. In the context of competitive markets and retail competition, the default rate is the rate the customer will pay if a competitive alternative is not affirmatively chosen by the customer.
See Also: "Opt-In," "Opt-Out," and "Default Service Customers."

Default Service Customers
Electricity consumers served by a competitive or restructured utility who do not affirmatively choose a power supplier. They are served with power procured by the distribution utility under rules established by the regulator.

Demand
In theory, an instantaneous measurement of the rate at which power or natural gas is being consumed by a single customer, customer class, or the entirety of an electric or gas system. Demand is expressed in kW or MW for electricity or therms for natural gas. Demand is the load-side counterpart to an electric system's capacity. In practical terms, electricity demand is actually measured as the average rate of energy consumption over a short period of time, usually 15 minutes or an hour. For example, a 1,000-watt hair dryer run for the entirety of a 15-minute demand interval would cause a demand meter using a 15-minute demand interval to record 1 kW of demand. If that same hair dryer were only run for seven and a half minutes, however, the measured demand would only be 0.5 kW. Metering of demand requires the use of either a demand meter or a smart meter.
See Also: "Capacity," "Interval Meter," and "Demand Charge."

Demand Charge
A charge paid on the basis of metered demand. Demand charges are usually expressed in dollars per watt units, for example kW (usually expressed as $/kW). Demand charges are common for large (and sometimes small) commercial and industrial customers, but have not typically been used for residential customers because of the high cost of demand meters. The widespread deployment of smart meters would enable the use demand charges for any customer served by those meters.
See Also: "Capacity," "Interval Meter," and "Demand."

Demand Meter
A meter capable of measuring and recording a customer's demand. Demand meters include conventional meters with separate demand registers, interval meters and smart meters.
See Also: "Demand," "Interval Meter," and "Smart Meter."

Demand Ratchet
A demand charge pricing scheme that charges for demand based on the highest metered demand over multiple billing cycles, usually one year. Demand ratchets have been justified on the theory that the system must be built to meet the maximum demand placed on it and a ratchet causes customers to pay for their own contribution to that demand based on their own maximum demand. Demand ratchets fail to capture the effects of time diversity and non-coincident of a customer's peak demand with the peak usage of any portion of the system. The increased temporal and geographic granularity of customer usage patterns made possible by smart meters obviates the need for demand ratchets and traditional demand charges.
See Also: "Demand Charge."

Demand-Related Cost
Costs which are associated primarily with the maximum demand placed on the system, as opposed to costs, such as fuel, which are driven primarily by total energy consumed. The term "demand-related cost" is an artifact of the era when utilities did not have precise data on the use of each customer or customer class at different hours of the day, and a time when all generation equipment had similar capital costs. This term was often applied to either all capital and operating costs of all generation, transmission, and shared distribution plant, or else to that portion determined necessary to meet peak demand. In an era where usage can be precisely measured by time period, and costs allocated accordingly, it is a somewhat anachronistic measurement.
See Also: "Energy-Related Cost."

Demand Response (DR)
Reduction in energy use in response to either system reliability concerns or increased prices (where wholesale markets are involved) or generation costs (in the case of vertically integrated utilities). Demand response must generally be measurable and controllable to participate in wholesale markets or be relied upon by system operators.

Demand-Response Program
A formalized system under which participating customers agree to reduce their consumption when called upon to do so. The agreement may be with their local utility (most likely under a formal tariff) or with a third-party curtailment service provider. The collective effect of the customers' reduction can be utilized by system operators to balance supply and demand or recognized by wholesale markets as an energy resource, paid at the prevailing market rate for energy at that point in time. Most demand-response programs limit the number of hours a given customer can be called upon to reduce usage. Participating customers are paid an incentive payment, in addition to the savings on their utility bill caused by their reduction in metered usage.

Distributed Energy Resources/ Demand-Side Resources (DER)
Any resource or activity at or near customer loads that generates energy or reduces energy consumption. Distributed energy resources include customer-sited generation, such as solar photovoltaic systems and emergency backup generators, as well as energy efficiency and controllable loads.

Distributed Generation (DG)
Any electricity generator located at or near customer loads. Distributed generation usually refers to customer-sited generation, such as solar photovoltaic systems, but may include utility-owned generation placed within the distribution system.
See Also: "Customer-Sited Generation."

Distribution
The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and below).

Distribution System
The portion of the electric system used to distribute energy to customers. The distribution system is usually distinguished from the transmission system on the basis of voltage. After energy is received from a generator's bus bar, its voltage is stepped up to very high levels where it is transported by the transmission system. Transmission system components carry energy at voltages as high 758 kW or higher and as low as 115 kV or lower. Different utilities use different voltage levels as the demarcation between transmission and distribution. Urban utilities may use a lower voltage because their systems quickly transition from long-distance transmission facilities to local distribution needs, while more rural utilities may treat higher voltage facilities as distribution because of the need to "distribute" energy over longer distances. Because energy losses increase with each passage through a transformer and as voltages decrease, there is a general design bias toward keeping energy at higher voltage levels as long as possible along the route between generation and load. Industrial customers may take service at transmission level voltages, in which case it would be inappropriate to allocated distribution system costs to them.
See Also: "Generation" and "Transmission."

Duration Curve
A graphic plot depicting, on a cumulative basis, the different prices (price duration curve), demand levels (load duration curve) or resource utilization (resource utilitzation duration curve) over the course of a specific time period.

Dynamic Pricing
Dynamic pricing creates changing prices for electricity that reflect actual wholesale electric market conditions. Examples of dynamic pricing include critical period pricing and real-time rates.

Economic Dispatch
The utilization of existing generating resources to serve load as inexpensively as possible.

Embedded Cost
A cost that has already been incurred or is unavoidable in the future. Rate cases based upon historical test years often use embedded cost-of-service studies that allocate the actual recorded historical investments (net of accumulated depreciation) and actual operating expenses among customer classes.
See Also: "Cost of Service Study" and "Marginal Cost."

Energy
A unit of demand consumed over a period of time. Energy is expressed in watt-time units, where the time units are usually one hour, such as 1 kilowatt-hour (kWh), 1 megawatt-hour (MWh), etc. An appliance placing 1 kW of demand on the system for one hour will consume 1 kWh of energy.

Energy Charge
A price component based on energy consumed. Energy charges are typically expressed in dollars per watt-hours, such as $/kWh or $/MWh.
See Also: "Energy," "Demand," and "Demand Charge."

Energy Conservation
The use of any device or activity that attempts to reduce energy, especially during times of system peaks. Energy conservation is usually meant to denote behavioral changes or changes in patterns of use. For example, increasing thermostat settings in the summer or decreasing them in the winter is a form of conservation. Energy conservation may last only so long as the associated behavior or usage pattern remains in effect.
See Also: "Energy Efficiency."

Energy Efficiency
The deployment of end-use appliances that achieve the same or greater end-use value while reducing the energy required to achieve that result. Higher-efficiency boilers and air conditioners, increased building insulation, and higher-energy-rated windows are all examples of energy efficiency. Energy efficiency implies a semi-permanent, longer-term reduction in the use of energy by the customer.
See Also: "Energy Conservation."

Energy Time-Shift
A process by which purchasing inexpensive electric energy, available during periods when price is low, to charge the storage plant so that the stored energy can be used or sold at a later time when the price is high. Entities that time-shift may be regulated utilities or nonutility merchants.

Energy-Related Cost
Any cost categorized as an energy cost in a cost of service study. Energy-related costs always include costs such as fuel and purchased power and may include other costs as well. The widespread deployment of smart meters may result in elimination of other cost categories, such as demand, in favor or more sophisticated time-of-use energy rates designs that would allocate all non-customer-related costs to energy.
See Also: "Fuel Cost," "Purchased Power," "Demand-Related Cost," and "Customer-Related Cost."

Externalities
Costs or benefits that are side effects of economic activities and are not reflected in the booked costs of the utility. Environmental impacts are the principal externalities caused by utilities (e.g., health-care costs as a result of air pollution).

Fixed Charge
Any fee or charge that does not vary consumption. Customer charges are a typical type of fixed charge. In some jurisdiction, customer are charged a connected load charge based on the size of their service panel or total expected maximum load. Minimum bills and straight/fixed variable rates are additional forms of fixed

charges.
See Also: "Minimum Bill," "Straight-Fixed/Variable Rate" and "Customer Charge."

Fixed Cost
An accounting term meant to denote costs that do not vary within a certain period of time, usually one year. This term is often misapplied to denote costs associated with plant and equipment (which are themselves denoted "fixed assets" in accounting terms) or other utility costs that cannot be changed in the short run. From a regulatory and economics perspective, the concept of fixed costs is irrelevant. For purposes of regulation, all utility costs are variable in the long run. The costs associated with seemingly fixed assets, such as the distribution system, are not fixed even in the short run. Utilities are constantly upgrading and replacing distribution facilities throughout their system as more customers are served and customer usage increases, and efforts to reduce demand can have immediate impacts on those costs.

Flat Rate
A rate design with a uniform price per kWh for all levels of consumption. A rate design that charges a single price for all consumption, typically used to denote that form of energy rate pricing.
See Also: "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Peak-Time Rebate," "Seasonal Rate," and "Straight-Fixed/Variable Rate."

Frequency
The cycles per second of an alternating current electric system. In most of North America, the electric system operates at a nominal 60 cycles per second (expressed in "hertz" as 60 Hz), while most of the rest of the world operates at 50 Hz. All of the generators connected to a single interconnection are required to synchronize the cycles of their own equipment to that of the entire system. From a system operator's point of view, loads must be constantly and near-instantaneously matched to generation output in order to maintain system frequency within a narrow allowed band (e.g., 59.9 to 60.1 Hz). When the frequency exceeds allowed limits, many generators and loads are designed to automatically disconnect from the grid, which may cause serious disruptions to service, including brownouts and blackouts.

Fuel Cost
The cost of fuel, typically burned, used to create electricity. Fuel types include nuclear, coal, natural gas, diesel, biomass, bagasse, wood, and fuel oil. Some generators, such as wind turbines and solar photovoltaic and solar thermal generators, use no fuel or, in the case of hydroelectric generation, virtually cost-free fuel.

Future Test Year/Projected Test Year
A regulatory accounting period that estimates the rate base and operating expenses a utility will incur to provide service in a future year, typically the first full year during which rates determined in that rate case will be in effect.
See Also: "Adjusted Test Year" and "Historical Test Year."

Generation
Any equipment or device that supplies energy to the electric system. Generation is often classified by fuel source (i.e., nuclear, coal, gas, solar, etc.) or by operational or economic characteristics ("must-run," baseload, intermediate, peaking, intermittment, load following, etc.).

Green Power
An offering of environmentally preferred power by a utility to its consumers, typically at a premium above the regular rate.

Grid
The electric system as a whole or as a reference to the non-generation portion of the system.

Grid Integration
The management of the variable power flows from generating units, maintaining power quality, and managing voltage and frequency stability. Variable renewable resources create different challenges for grid integration than conventional generating units, including minute-to-minute variations in output, periods of large wind generation shortfall, and power quality issues created by wind gusts.

Historical Test Year
A regulatory accounting period that measures the actual costs that a utility incurred to provide service in a 12-month period, typically adjusted for known and measurable changes that have occurred or are expected to occur afterward.
See Also: "Adjusted Test Year" and "Historical Test Year."

IEEE 1547
A industry standard governing the engineering and performance criteria for interconnection of customer-sited generation to the electric system. When a proposed interconnection meets certain criteria, it is usually allowed to proceed without any further review or approval of the utility, except for the execution of a required interconnection agreement. This is the case unless the interconnection would cause the total capacity of customer-sited generation on local parts of the distribution system to exceed certain threshold or would be expected to create a situation-specific safety or reliability hazard to the system or the public. Generally, under the terms of the original IEEE 1547, a customer-sited generator would be required to automatically disconnect from the system and the customer's load in the event the grid fails or becomes unstable. An updated version, IEEE 1547.8, is currently being drafted for "smart inverters" to enable smart grid functions that allow system operators to communicate with the inverter, dispatch it for certain ancillary services, and allow the PV unit to continue to serve the customer's load in the event the grid becomes unstable or unavailable.
See Also: "Distributed Generation."

Incentive Regulation/Performance-Based Regulation (PBR)
A form of regulation in which the utility is given specific performance targets or benchmarks to achieve and is rewarded financially for meeting or exceeding them and, optionally, penalized for failing to meet them. In a sense, all regulation is incentive regulation, but, as a term of art, this refers specifically to the formal system of establishing rewards and penalties for specific performance criteria such as cost controls, reliability and customer service.
See Also: "Decoupling" and "Revenue Regulation."

Inclining Block Rate
A form of rate design in which blocks of energy usage have increasing prices as the amount of usage increases. Inclining block rates appropriately, if crudely, reflect the fact that increased costs are associated with greater usage. They enhance the economics of energy efficiency and renewable energy by increasing the savings a customer can achieve by reducing energy purchases from the utility.
See Also: "Flat Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Peak-Time Rebate," "Seasonal Rate" and "Straight-Fixed/Variable Rate."

Incremental Cost
A cost of study method based on the short-run cost of augmenting an existing system. An incremental cost study rests on the theory that prices should reflect the cost of producing the next unit of energy or deploying the next unit of capacity in the form of generation, transmission or distribution.

Independent Power Plant (IPP)/Merchant Power Plant
A power plant that operates in a competitive market and is not directly included in the rates of a regulated utility or subject to general utility regulation.

Integrated Resource Planning (IRP)
A public planning process and framework within which the costs and benefits of both demand and supply-side resources are evaluated to develop the least total-cost mix of utility resource options. Also known as least-cost planning.

Interconnection Agreement
A contract between a utility and a customer governing the connection and operation of customer-sited generation which is operated synchronously with the electric system.
See Also: "Distributed Generation," "Net Energy Metering" and "IEEE 1547."

Interval Meter
A meter capable of measuring and recording a customer's usage over a defined period of time.

Intervenor
An individual, group, or institution that is officially involved in a rate case.

Kilowatt (kW)
A kilowatt is equal to 1,000 watts.
See Also: "Watt."

Kilowatt-hour (kWh)
A kilowatt-hour is equal to 1,000 watt-hours.
See Also: "Watt-hour."

Line Transformer
A transformer directly providing service to a customer, either on a dedicated basis or among a small number of customers.

Load
The combined demand for electricity placed on the system. The term is sometimes used in a generalized sense to simply denote the aggregate of customer energy usage on the system, or in a more specific sense to denote the customer demand at a specific point in time.

Load Following
The process of matching variations in load over time by increasing or decreasing generation supply or, conversely, decreasing or increasing loads. One or more generating units or demand response resources will be designated as the load following resources at any given point in time. Baseload and intermediate generation is generally excluded from this category except in extraordinary circumstances.

Load Management
Active control of customer usage levels for the purpose of avoiding the use of high-cost supply resources or in response to system reliability needs.

Long-Run Marginal Costs
The long-run costs of the next unit of electricity produced, including the cost of a new power plant, additional transmission and distribution, reserves, marginal losses, and administrative and environmental costs. Also called long-run incremental costs.

Losses/Energy Losses/Technical Losses/ Non-Technical Losses
The energy (kWh) and power (kW) lost or unaccounted for in the operation of an electric system. Losses are usually in the form of energy lost to heat, sometimes referred to as "technical losses"; however, energy theft from illegal connections or tampered meters, sometimes referred to as "non-technical losses," will also contribute to losses.
See Also: "Energy" and "Lost Revenue Adjustment Mechanism."

Lost Revenue Adjustment Mechanism (LRAM)
A mechanism by which a regulator allows a utility to recovery the sales margins that are lost when customers participate in utility-sponsored energy efficiency or renewable energy programs.
See Also "Decoupling."

Marginal Cost
The long-run costs of the next unit of electricity producted, including the cost of a new power plant, additional transmission and distribution, reserves, marginal line losses, and administrative and environmental costs. Long-run marginal costs should look at the cost of building a new utility system, not just the costs of augmenting output from an existing system. Also called long-run incremental costs (LRIC) or total system long-run incremental costs (TSLRIC).

Megawatt (MW)
A megawatt is equal to one million watts or 1,000 kilowatts.
See Also: "Watt."

Megawatt-Hour (MWh)
A megawatt-hour is equal to one million watt-hours or 1,000 kilowatt-hours.
See Also: "Watt-hour."

Meter Data Management System (MDMS)
A computer and control system which gathers metering information from smart meters, makes it available to the utility and, optionally, to the customer. A meter data management system is part of the suite of smart technologies and is integral to the smart grid concept.
See Also: "Smart Grid" and "Smart Meter."

Microgrid
A localized grouping of electricity sources and loads that normally operates connected to and synchronous with the traditional centralized grid (macrogrid), but can disconnect and function autonomously as physical and/or economic conditions dictate.

Minimum Bill
A rate design that charges a minimum amount of money in return for a designated amount of energy, which must be paid even if they customer's actual usage is less that amount of energy.

Minimum Charge
A rate-schedule provision stating that a customer's bill cannot fall below a specified level. These are common for rates that have no separate customer charge.

Municipal Utility (Muni)
A utility owned by a unit of government, and operated under the control of a publicly elected body. About 15% of Americans are served by munis.

Net Energy Metering (NEM)/Net Metering
A rate design which allows a customer with distributed generation, typically solar photovoltaic systems, to receive a bill credit at the full retail rate for all energy injected into the electric system.

Non-Coincident Demand (NCD)/Non-Coincident Peak Load
A customer's maximum energy demand during a billing period or a year, even if it is different from the time of the system peak demand.
See Also: "Coincident Peak" and "System Peak."

Off-Peak
The period of time that is not on-peak. During off-peak periods, system costs are generally lower and system reliability is not an issue. Time-of-use rates typically have off-peak prices which are lower than on-peak prices.
See Also: "On-Peak."

On-Peak
The period of time when customer demand is higher than normal. During on-peak periods, system costs are higher than average and reliability issues may be present. Many rate designs and utility "programs" are oriented to reducing on-peak usage. Planning and investment decisions are often driven by expectations about the timing and magnitude peak demands during on-peak period. Time-of-use rates typically have on-peak prices that are higher than off-peak prices.
See Also: "Off-Peak."

Opt-In
A way of determining whether customers will be placed on an alternative or new rate schedule. In an opt-in approach, customers will only be placed on the rate schedule if they actively choose that option. The opt-in approach assures that customers are not placed on a rate schedule without their express permission, but will typically result in fewer customers taking the new rate.
See Also: "Opt-Out."

Opt-Out
A way of determining whether customers will be placed on an alternative or new rate schedule. In an opt-out approach, customers will automatically be placed on the rate schedule unless they actively to choose to stay on their existing rate schedule. The opt-out approach results in a participation rate on the new rate schedule, but risks placing customers on a rate without their knowledge and consent.
See Also: "Opt-In."

Payback Period
The amount of time required for the net revenues of an investment to return its costs. This metric is often employed as a simple tool for evaluating energy efficiency measures.

Peak Demand
The maximum demand by a single customer, a group of customers located on a particular portion of the electric system, all of the customers in a class, or all of a utility's customers during a specific period of time — hour, day, month, season or year.

Peak Load
The maximum total demand on a utility system during a period of time.

Peaking Resource/Peaking Generation/Peaker
Generation that is used to serve load during periods of high demand. Peaking generation typically has high fuel costs or limited availability (e.g., pumped storage hydro generation), but often has low capital costs. Peaking generation is used a limited number of hours, especially as compared baseload generation. Peaking resources may connote non-generation resources such as storage or demand-side resources.
See Also: "Baseload Generation."

Peak-Time Rebate (PTR)
A rate design which provides a bill credit to a customer who reduces usage below a baseline level during a period of high peak demand or when system reliability may be at risk. Peak-time rebates are an alternative to critical peak pricing rate designs.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Seasonal Rate" and "Straight-Fixed/Variable Rate."

Photovoltaic (PV) Systems
An electric generating system utilitzing photovoltaic cells to generate electricity from sunlight. PV systems may be either used in off-grid, stand-alone applications, or operated synchronously with the electric system by interconnecting through a power inverter which converts their output to system quality, AC power, which is synchronized with the AC cycles of the electric system. In the United States, synchronous operation requires the use of an inverter that meets the standards of IEEE 1547, in addition to possible additional requirements of the local utility.

Power Factor
The fraction of power actually used by a customer's electrical equipment compared with the total apparent power supplied, usually expressed as a percentage. A power factor indicates the extent to which a customer's electrical equipment causes the electric current delivered at the customer's site to be out of phase with system voltage.

Power Quality
Technical metrics applied to the voltage stability, frequency, waveform, and other details of electricity supply. These include power factor (reactive power), harmonic distortion, and other factors that affect the performance of electrical and electronic equipment connected to the grid.

Price Cap
The highest price allowed in the wholesale market and is a price mitigation tool. An "offer cap" is the highest price that a resource, including DR, can offer to the wholesale market. "DR" means the demand response treatment in the market.

Prudence Review
The process by which a regulator determines the prudence of utility resource decisions. If a cost is found imprudent, it may be disallowed from rates. While retrospective, prudence reviews are typically determined on the basis of the information available to decision-makers at the time the decision was made.

Purchased Power Cost
The cost incurred by a utility to purchase energy from another entity. Purchased power costs are usually collected through a utility's fuel and purchased power adjustment clause and typically have no markup or profit-adder for the utility. Power may be purchased in organized markets at the market clearing price or through bilateral contracts, which may specify resource, prices, timing and other terms and have reservation or demand charges in addition to energy charges.

Rate Base
The appropriate value for ratemaking purposes of the utility's investment in utility plant and other assets, including working capital, that is "used and useful" in providing service to the public.
See Also: "Used and Useful."

Rate Case
A proceeding, usually before a regulatory commission, involving the rates and policies of a public utility.

Rate Design
Specification of prices for each component of a rate schedule for each class of customers, which are calculated to produce the revenue requirement allocated to the class. In simple terms, prices are equal to revenues divided by billing units, based on historical or assumed usage levels. Total costs are allocated across the different price components such as customer charges, energy charges, demand charges and each price component is then set at the level required to generate sufficient revenues to cover those costs.

Rate of Return
A percentage value which is multiplied by rate base to determine a portion of the revenue requirement. The rate of return is equal to the utility's weighted cost of capital.
See Also: "Cost of Capital," "Cost of Equity," "Cost of Debt," and "Weighted Cost of Capital."

Reactive Power
In an energized electric system, a portion of the energy injected into the system is initially diverted into magnetic fields. In a perfectly designed and operated system, this is a one-time injection of energy and all additional energy injected into the system is delivered to end-use appliances or lost as heat. When the system is de-energized, the energy use to create the magnetic field is recovered. In reality, some end-use appliances, typically motors as they commence operation, can draw some of their energy requirements from the magnetic field, rather than from the

intended flow of energy, causing the customer's load to become out of phase with the system. Additional energy must then be injected into the system to maintain the magnetic field. This energy is termed reactive power. Customers whose equipment draws reactive power from the system are typically charged a power factor adjustment to account for this phenomenon.
See Also: "Power Factor."

Real-Time Pricing (RTP)/Dynamic Pricing
Establishing rates that adjust as frequently as hourly, based on wholesale electricity costs or actual generation costs.

Reliability
A measure of the ability of the electric system to provide continuous service to customers over time. Reliability is often measure in terms of "loss of load probability" (LOLP). The US-Canadian-Mexican interconnections generally experience extremely high reliability. Reliability standards are set and maintained by the North American Electric Reliability Corporation and its regional counterparts, as well as by RTOs/ISOs and electric utilities. Compliance with reliability standards is compulsory.

Renewable Energy Certificate (REC)/ Renewable Energy Credit/ Green Certificate/Green Tag/ Tradable Renewable Certificate
Documentation of energy produced by a renewable energy resource. RECs can be severed from the energy produced and separately traded. Utilities that must comply with a renewable portfolio standard usually are required to document their compliance by possessing RECs, through their own generation or by purchasing RECs from third-parties, to document the production of energy from renewable resources.
See Also: "Renewable Resources" and "Renewable Portfolio Standard."

Renewable Portfolio Standard (RPS)
A regulatory requirement that utilities meet a specified percentage of their power supply using qualified renewable resources.
See Also: "Renewable Resources" and "Renewable Energy Certificate."

Renewable Resources
Power generating facilities that use wind, solar, hydro, biomass, or other non-depleting fuel sources. In some states, qualified renewable resources exclude large hydro stations or some other types of generation.

Reserve Account
An allowed accumulation of revenues in excess of regularly occurring costs of service that may be drawn down in the event the utilities revenues are less than expected or its expenses are greater than expected.

Reserve Capacity/Reserve Margin/Reserves
The amount of capacity that a system must be able to supply, beyond what is required to meet demand, in order to assure reliability when one or more generating units or transmission lines are out of service. Traditionally, a reserve capacity of 15–20 percent was thought to be needed for good reliability. In recent years, the accepted value in some areas has declined to 10 percent or even lower.

Reserves Shortage Pricing
Pricing and penalties that are invoked by a system operator in cases of reduced power reserves to ensure sufficient generation is available when needed.

Restructured State/Restructured Market
Replacement of the traditional vertically integrated electric utility with some form of competitive market. In some cases, the generation and transmission components of service are purchased by the customer-serving distribution utility in a wholesale competitive market. In other cases, retail customers are allowed to choose their generation suppliers directly in a competitive market.
See Also: "Retail Choice."

Retail Choice/Retail Competition
A restructured market in which customers are allowed or must choose their own competitive supplier of generation and transmission services. In most states with retail choice, the incumbent utility or some other identified entity is designated as a default service provider for customers who, through inaction, do not choose another supplier. In Texas, there is no default service provider and all customers must make a choice.

Return on Equity
The profit rate allowed to the shareholders of an investor-owned utility, expressed as a percentage of the equity capital invested.

Revenue per Customer/Revenue per Customer Adjustment (RPC)
A form of revenue decoupling. RPC allows the target revenue for revenue decoupling to be adjusted based on the number of customers being served. In it's usual application, at the end of a rate case the allowed revenue to be collected from each billing component (i.e., customer charge, energy charge, demand charge, etc.) is divided by the adjusted test year billing units to derive an RPC value. In subsequent periods, the allowed revenue is recomputed by multiplying the actual number of customers being served by the RPC values for each rate component. That revenue value is then divided by the actual billing units for that period to derive the new price to be charged customers.
See Also: "Decoupling" and "Adjusted Test Year."

Revenue Regulation
A regulator approach which allows a utility to collect a target revenue level, regardless of its sales volume. The target revenue may be fixed between rate cases or may be allowed to change formulaically between rate cases.
See Also: "Decoupling" and "Lost Revenue Adjustment Mechanism."

Revenue Requirement
The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base. In most contexts, revenue requirement and cost of service are synonymous.

Seasonal Rate
A rate that is higher during the peak-usage months of the year. Seasonal rates are intended to reflect differences in the underlying costs of providing service associated with different times of the year.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," "Peak Time Rebate" and "Straight-Fixed/Variable Rate."

Service Drop
A transformer, conductor, pole, or underground facilities connecting a single customer to the electric system.

Smart Appliance
An appliance which is capable of communicating with a customer- or utility-owned data acquisition and control system.
See Also: "Smart Grid," "Smart Meter," and "Smart Technology."

Smart Grid
An integrated network of sophisticated meters, computer controls, information exchange, automation, and information processing, data management, and pricing options that can create opportunities for improved reliability, increased consumer control over energy costs, and more efficient utilization of utility generation and transmission resources.
See Also: "Smart Appliance," "Smart Meter," and "Smart Technology."

Smart Meter
An electric meter with electronics that enable recording of customer usage in short time intervals and two-way communication of data between the utility and the meter (and, optionally, the customer).
See Also: "Smart Appliance," "Smart Grid," and "Smart Technology."

Smart Technology
The collection of smart meters, smart appliances, system control and data acquisition systems and meter data management systems, which together enable utilities, system operators and customer to monitor current conditions and control one or more portions of the electric grid and connected appliances to optimize costs and reliability.
See Also: "Smart Appliance," "Smart Grid," and "Smart Meter."

Spinning Reserve
Any energy resource which can be called upon within a designated period of time which system operators may use to balance loads and resources. Spinning reserves may be in the form of generators, energy storage or demand response. Spinning reserves may be designated by how quickly they can be made available, from instantaneously up to some short period of time.

Standby Service
Support service that is available, as needed, to supplement supply for a consumer, a utility system, or another utility if normally scheduled power becomes unavailable. The unavailable source may be a third party provider or a customer-owned generator.

Straight-Fixed/Variable Rate (SFV)
A rate design method that recovers all short-run fixed costs in a fixed charge, and only short-run variable costs in a per-unit charge.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Time-of-Use Rate," "Critical Peak Pricing," and "Peak-Time Rebate."

Substation
A facility with a transformer that steps voltage down from a portion of the system which transports energy in greater bulk and to which one or more circuits or customers may be connected.

Supervisory Control and Data Acquisition (SCADA)
A collection of sensors, meters, communications equipment and computers that monitors the status of any portion of the electric system, reports that status to system operators, utilities, and optionally, customers and provides for control of system equipment and, optionally, end-use appliances to optimize costs and reliability.

System Peak Demand
The maximum demand placed on the electric system at a single point in time. System peak demand may be measure for an entire interconnection, for sub-regions within an interconnection or for individual utilities or service areas.

Tariff
A listing of the rates, charges, and other terms of service for a utility customer class, as approved by the regulator.

Therm
A unit of natural gas equal to 100,000 Btu. The quantity is approximately 100 cubic feet, depending on the exact chemical composition of the natural gas.

Time-of-Use Rate/Time-Differentiated Rate (TOU)
Rates that vary by time of day and day of the week. TOU rates are intended to reflect differences underlying costs incurred to provide service at different times of the day or week.
See Also: "Flat Rate," "Inclining Block Rate," "Declining Block Rate," "Critical Peak Pricing," "Peak-Time Rebate," "Seasonal Rate" and "Straight-Fixed/Variable Rate."

Tracker
A rate schedule provision giving the utility company the ability to change its rates at different points in time, to recognize changes in specific costs of service items without the usual suspension period of a rate filing.
See Also: "Adjustment Clause."

Transformer
A device that raises ("steps up") or lowers ("steps down") the voltage in an electric system. Electricity coming out a generator is often stepped up to very high voltages (345 kW or higher) for injection into the transmission system and then repeatedly stepped down to lower voltages as the distribution system fans out to connect to end-use customers. Some energy loss occurs with every voltage change. Generally, higher voltages can transport energy for longer distances with fewer energy losses.

Transmission Voltage
Voltage levels used to in the transmission system for transport of power to substations. Transmission voltages are generally above 50kV.
See Also: "Transmission."

Transmission/Transmission System
That portion of the electric system designed to carry energy in bulk. The transmission system is operated at the highest voltage of any portion of the system. It usually designed to either connect remote generation to local distribution facilities or to interconnect two or more utility's systems to facilitate exchanges of energy between systems.
See Also: "Distribution" and "Generation."

Unit Cost
The costs allocated to a specific function, such as demand or energy, divided by the billing units for function (billed demand or billed energy). The result is expressed in dollars per unit, as in $/kW or $/kWh.

Used and Useful
A regulatory concept — often triggered when plant is first placed in service, but applicable throughout the life of the plant — for determining whether utility plant is eligible for inclusion in a utility's rate base. While different state courts have interpreted the concept differently, utility plant is generally considered "used" if it is actually used or is available for use in providing service to the public. This includes reserve inventories available to replace failed equipment or for upgrades and expansions anticipated in the near future, as well reasonable levels of generation "reserves" in excess of that needed to serve the utility's anticipated peak load. Utility plant is generally considered "useful" if it is the appropriate kind of plant to be used in providing service and is available at a reasonable cost. To be included in a utility's rate base or expenses, plant must satisfied both of these conditions. For example, a combined-cycle gas turbine might be both used and useful, while a highly inefficient oil-fired plant that cannot meet emissions requirements would not, even though they might both be actually used to generate electricity during a rate case test year. Alternatively, that same combined-cycle plant might be useful, but unused because the utility has sufficient other resources to provide service.

Value of Solar Tariff (VOST)
A tariff that pays for the injection of solar generated power into the electric system at a price based on its value. The valuation of solar is usually based on some or all of the following: avoided energy costs, avoided capital costs, avoided O&M expenses, avoided system losses, avoided spinning and other reserves, avoided social costs, any other avoided costs, less any increased costs incurred on account of the presence of solar resources, such as backup resources, spinning reserves, transmission or distribution system upgrades or other identifiable costs. A VOST is an alternative to net energy metering and non-value-based feed-in tariffs.
See Also: "Net Energy Metering" and "Feed-In Tariff."

Vehicle-to-Grid (V2G)
The process of treating elecric vehicles as a distributed resource for the electric grid and allowing system operators to withdraw power from them or store energy in them or later use, with the constraint that they will be adequately charged for use when needed by the EV driver.

Volt
A unit of measurement of electromotive force. Typical transmission level voltages are 115 kV, 230 kV and 500 kV. Typical distribution voltages are 4 kV, 13 kV, and 34 kV.

Voltage Support
An ancillary service in which the provider's equipment is used to maintain system voltage within a specified range.
See Also: "Ancillary Service."

Watt
The electric unit used to measure power, capacity or demand. Equivalent to one joule per second and equal to the power in a circuit in which a current of one ampere flows across a potential difference of one volt. One kilowatt = 1,000 watts. One megawatt = one million watts or 1,000 kilowatts.

Watt-Hour
The amount energy generated or consumed with one watt of power over the course of one hour. One kWh equals 1,000 watts consumed or delivered for one hour. One MWh equals one million watts consumed or delivered for one hour. The W is capitalized in the acronym in recognition of electrical pioneer James Watt.

Weather Normalization
An adjustment made to test year sales to remove the effects of abnormal weather. Because many end uses, especially air conditioning and heating, vary with temperature, there is a direct correlation between weather conditions and energy sales. The

objective in weather normalization is characterize the sales a utility would have is the weather experienced during a specific period had been the same as the average weather over some sufficiently long period of time, usually 20 to 30 years.
See Also: "Adjustment Clause" and "Decoupling."

Weatherization

A process or program for increasing a building's thermal efficiency. Examples include caulking windows, weather stripping, and adding insulation to the wall, ceilings, and floors.

Weighted Cost of Capital

A composite cost rate that reflects the cost of debt and cost of equity in proportion to their respective share of the utility's capital structure. The weighted cost of capital is sometimes expressed in after-tax terms, so that income taxes on the cost of equity and tax savings on the cost of debt are accounted for. The weighted cost of capital is the rate of return normally applied to rate base in the computation of a utility's revenue requirement.
See Also: "Cost of Capital," "Cost of Equity," "Cost of Debt," "Capital Structure" and "Rate of Return."

Related Resources

Electricity Regulation in the United States: A Guide

http://www.raponline.org/document/download/id/645

This 120-page guide offers a broad look at utility regulation in the US. Its intended audience includes anyone involved in the regulatory process, from regulators to industry to advocates and consumers. The chapters briefly touch on most topics that affect utility regulation, but do not go into depth on each topic as the discussion is intended to be short and understandable. A lengthy glossary appears at the end of this guide to explain utility sector terms.

Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed

http://www.raponline.org/document/download/id/6516

This paper identifies sound practices in rate design applied around the globe using conventional metering technology. Rate design for most residential and small commercial customers (mass market consumers) is most often reflected in a simple monthly access charge and a per-kWh usage rate in one or more blocks and one or more seasons. A central theme across the practices highlighted in this paper is that of sending effective pricing signals through the usage-sensitive components of rates in a way that reflects the character of underlying long-run costs associated with production and usage. While new technology is enabling innovations in rate design that carry some promise of better capturing opportunities for more responsive load, the majority of the world's electricity usage is expected to remain under conventional pricing at least through the end of the decade, and much longer in some areas. Experience to date has shown that the traditional approaches to rate design persist well after the enabling technology is in place that leads to change.

Time-Varying and Dynamic Rate Design

http://www.raponline.org/document/download/id/5131

This report discusses important issues in the design and deployment of time-varying rates. The term, time-varying rates, is used in this report as encompassing traditional time-of-use rates (such as time-of-day rates and seasonal rates) as well as newer dynamic pricing rates (such as critical peak pricing and real time pricing). The discussion is primarily focused on residential customers and small commercial customers who are collectively referred to as the mass market. The report also summarizes international experience with time-varying rate offerings.

Designing Distributed Generation Tariffs Well

http://www.raponline.org/document/download/id/6898

Improvements in distributed generation economics, increasing consumer preference for clean, distributed energy resources, and a favorable policy environment in many states have combined to produce significant increases in distributed generation adoption in the United States. Regulators are looking for the well-designed tariff that compensates distributed generation adopters fairly for the value they provide to the electric system, compensates the utility fairly for the grid services it provides, and charges non-participating consumers fairly for the value of the services they receive. This paper offers regulatory options for dealing with distributed generation. The authors outline current tariffs and ponder what regulators should consider as they weigh the benefits, costs, and net value to distributed generation adopters, non-adopters, the utility, and society as a whole. The paper highlights the importance of deciding upon a valuation methodology so that the presence or absence of cross-subsidies can be determined. Finally, the paper offers rate design and ratemaking options for regulators to consider, and includes recommendations for fairly implementing tariffs and ratemaking treatments to promote the public interest and ensure fair compensation.

Revenue Regulation and Decoupling: A Guide to Theory and Application

http://www.raponline.org/document/download/id/902

This guide was prepared to assist anyone who needs to understand both the mechanics of a regulatory tool known as decoupling and the policy issues associated with its use. This would include public utility commissioners and staff, utility management, advocates and others with a stake in the regulated energy system. While this guide is somewhat technical at points, we have tried to make it accessible to a broad audience, to make comprehensible the underlying concepts and the implications of different design choices. This guide includes a detailed case study that demonstrates the impacts of decoupling using different pricing structures (rate designs) and usage patterns.

Decoupling Case Studies: Revenue Regulation Implementation in Six States

http://www.raponline.org/document/download/id/7209

This paper examines revenue regulation, popularly known as decoupling, and the various elements of revenue regulation that can be assembled in numerous ways based on state priorities and preferences to eliminate the throughput incentive. This publication focuses on six utilities: Pacific Gas and Electric Company, Idaho Power Company, Baltimore Gas and Electric Company, Wisconsin Public Service Company, National Grid-Massachusetts, and Hawaiian Electric Company, and the different forms of revenue regulation their regulators have implemented. These examples examine the details of revenue regulation and provide a range of options on how to implement revenue regulation. These specific utilities were chosen in order to represent a range of mechanisms used throughout the US and to contrast differences to provide a broader overview of the options available in designing decoupling mechanisms and to describe how they have worked to assist state regulators and utilities considering implementing revenue regulation.

Charging for Distribution Utility Services: Issues in Rate Design

http://www.raponline.org/document/download/id/412

In this report, we evaluate rate structures for electric distribution services, including embedded and marginal cost valuation methods, approaches and principles of rate design, and interactions with competitive markets.

Pricing Do's and Don'ts: Designing Retail Rates as if Efficiency Counts

http://www.raponline.org/document/download/id/939

Rate design is a crucial element of an overall regulatory strategy that fosters energy efficiency and sends appropriate signals about efficient system investment and operations. Rate design is also fully under the control of state regulators. Progressive rate design elements can guide consumers to participate in energy efficiency programs and reduce peak demand, yet relatively few utilities and commissions have implemented many of these elements. This RAP paper identifies some best practices. Because pricing issues tie closely to utility growth incentives, we also address revenue decoupling.

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Exhibit No. EERMC - SP-3

ROCKY MOUNTAIN INSTITUTE

THE ECONOMICS OF DEMAND FLEXIBILITY

HOW "FLEXIWATTS" CREATE QUANTIFIABLE VALUE FOR CUSTOMERS AND THE GRID

1820 FOLSOM STREET | BOULDER, CO 80302 | RMI.ORG

PUBLISHED AUGUST 2015
DOWNLOAD AT: WWW.RMI.ORG/ELECTRICITY_DEMAND_FLEXIBILITY

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SUGGESTED CITATION

Dyson, Mark, James Mandel, et al. *The Economics of Demand Flexibility: How "flexiwatts" create quantifiable value for customers and the grid.* Rocky Mountain Institute, August 2015. <<http://www.rmi.org/electricity_demand_flexibility>>

ACKNOWLEDGMENTS

The authors thank the following individuals and organizations for offering their insights and perspectives on this work:

Pierre Bull, Natural Resources Defense Council
Karen Crofton, Rocky Mountain Institute
James Fine, Environmental Defense Fund
Ellen Franconi, Rocky Mountain Institute
William Greene, Nest Labs
Leia Guccione, Rocky Mountain Institute
Lena Hansen, Rocky Mountain Institute
Ryan Hledik, The Brattle Group
Marissa Hummon, Tendril
Ian Kelly, Rocky Mountain Institute
Tom Key, Electric Power Research Institute
Virginia Lacy, Rocky Mountain Institute
Jim Lazar, The Regulatory Assistance Project
Amory Lovins, Rocky Mountain Institute
Farshad Samimi, Enphase Energy
Daniel Seif, The Butler Firm
James Sherwood, Rocky Mountain Institute
Owen Smith, Rocky Mountain Institute
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ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. In 2014, RMI merged with Carbon War Room (CWR), whose business-led market interventions advance a low-carbon economy. The combined organization has offices in Snowmass and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

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EXEC

EXECUTIVE SUMMARY

Electric utilities in the United States plan to invest an estimated $1+ trillion in traditional grid infrastructure—generation, transmission, and distribution—over the next 15 years, or about $50–80 billion per year, correcting years of underinvestment. However, official forecasts project slowing electricity sales growth in the same period (less than 1% per year), coming on the heels of nearly a decade of flat or declining electricity sales nationwide. This is likely to lead to increasing retail electricity prices for customers over the same period.

Meanwhile, those customers enjoy a growing menu of increasingly cost-effective, behind-the-meter, distributed energy resource (DER) options that provide choice in how much and when to consume and even generate electricity. These dual trends and how customers might respond to them—rising prices for retail grid electricity and falling costs for DER alternatives that complement (or in extreme cases even supplant) the grid—has caused considerable electricity industry unrest. It also creates a potential for overinvestment in and duplication of resources on both sides of the meter.

Yet utility and customer investments on both sides of the meter are based on the view that demand profiles are largely inflexible; flexibility must come solely from the supply side. Now, a new kind of resource makes the demand side highly flexible too. *Demand flexibility* (DF) evolves and expands the capability behind traditional demand response programs. DF allows demand to respond continuously to changing market conditions through price signals or other mechanisms. DF is proving a grossly underused opportunity to buffer the dynamic balance between supply and demand. When implemented, DF can create quantifiable value (e.g., bill savings, deferred infrastructure upgrades) for both customers and the grid.

Here, we analyze demand flexibility's economic opportunity. In the residential sector alone, widespread implementation of demand flexibility can save 10–15% of potential grid costs, and customers can cut their electric bills 10–40% with rates and technologies that exist today. Roughly 65 million customers already have potentially appropriate opt-in rates available, so the aggregate market is large and will only grow with further rollout of granular retail pricing.

DEMAND FLEXIBILITY DEFINED

Demand flexibility uses communication and control technology to shift electricity use across hours of the day while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality but lower cost. It does this by applying automatic control to reshape a customer's demand profile continuously in ways that either are invisible to or minimally affect the customer, and by leveraging more-granular rate structures that monetize demand flexibility's capability to reduce costs for both customers and the grid.

Importantly, demand flexibility need not complicate or compromise customer experience. Technologies and business models exist today to shift load seamlessly while maintaining or even improving the quality, simplicity, choice, and value of energy services to customers.

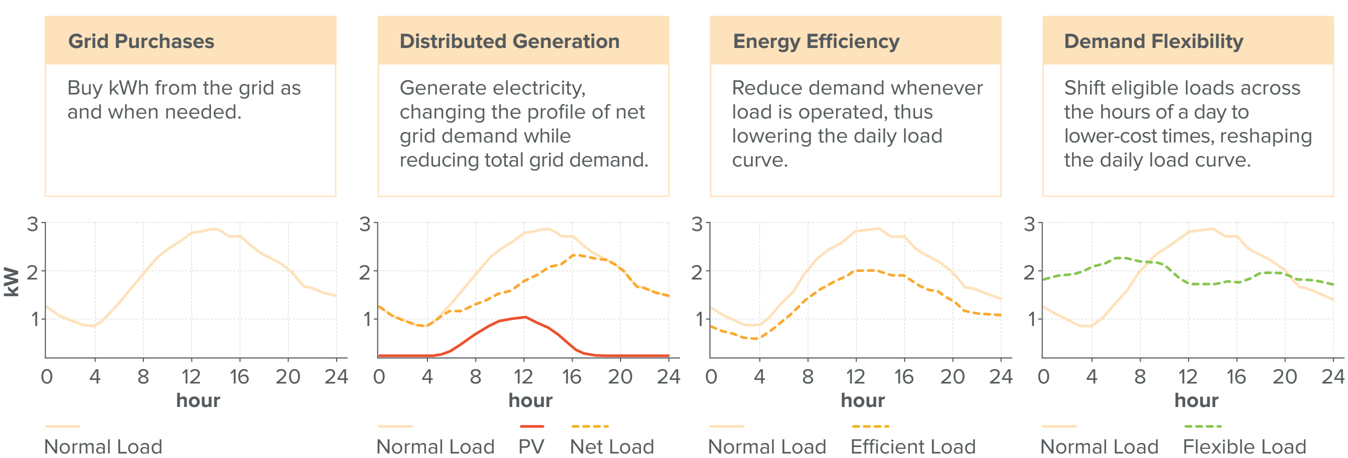
THE EMERGING VALUE OF FLEXIWATTS: THE BROADER OPPORTUNITY FOR DERs TO LOWER GRID COSTS

Electric loads that demand flexibility shifts in time can be called *flexiwatts*—watts of demand that can be moved across the hours of a day or night according to economic or other signals. Importantly, flexiwatts can be used to provide a variety of grid services (see Table ES1). Customers have an increasing range of choices to meet their demand for electrical services beyond simply purchasing kilowatt-hours from the grid at the moment of consumption. Now they can also choose to generate their own electricity through distributed generation, use less electricity more productively (more-efficient end-use or negawatts), or shift the timing of consumption through demand flexibility (see Figure ES1). All four of these options need to be evaluated holistically to minimize cost and maximize value for both customers and the grid.

TABLE ES1
FUNDAMENTAL VALUE DRIVERS OF DEMAND FLEXIBILITY

CATEGORY	DEMAND FLEXIBILITY CAPABILITY	GRID VALUE	CUSTOMER VALUE
Capacity	Can reduce the grid's peak load and flatten the aggregate demand profile of customers	Avoided generation, transmission, and distribution investment; grid losses; and equipment degradation	Under rates that price peak demand (e.g., demand charges), lowers customer bills
Energy	Can shift load from high-price to low-price times	Avoided production from high-marginal-cost resources	Under rates that provide time-varying pricing (e.g., time-of-use or real-time pricing), lowers customer bills
Renewable energy integration	Can reshape load profiles to match renewable energy production profiles better (e.g., rooftop solar PV)	Mitigated renewable integration challenges (e.g., ramping, minimum load)	Under rates that incentivize onsite consumption (e.g., reduced PV export compensation), lowers customer bills

FIGURE ES1
GRID PURCHASES, DISTRIBUTED GENERATION, ENERGY EFFICIENCY, AND DEMAND FLEXIBILITY COMPARED



FINDINGS

Residential demand flexibility can avoid $9 billion per year of forecast U.S. grid investment costs—more than 10% of total national forecast needs—and avoid another $4 billion per year in annual energy production and ancillary service costs.

While our analysis focuses primarily on demand flexibility's customer-facing value, the potential grid-level cost savings from widespread demand flexibility deployment should not be ignored. Examining just two residential appliances—air conditioning and domestic water heating—shows that ~8% of U.S. peak demand could be reduced while maintaining comfort and service quality. Using industry-standard estimates of avoided costs, these peak demand savings can avoid $9 billion per year in traditional investments, including generation, transmission, and distribution. Additional costs of up to $3 billion per year can be avoided by controlling the timing of a small fraction of these appliances' energy demands to optimize for hourly energy prices, and $1 billion per year from providing ancillary services to the grid. The total of $13 billion per year (see Figure ES2) is a conservative estimate of the economic potential of demand flexibility, because we analyze a narrow subset of flexible loads only in the residential sector, and we do not count several other benefit categories from flexibility that may add to the total value.[1]

Demand flexibility offers substantial net bill savings of 10–40% annually for customers.

Using current rates across the four scenarios analyzed, demand flexibility could offer customers net bill savings of 10–40%. Across all eligible customers in each analyzed utility service territory, the aggregate market size (net bill savings) for each scenario is $110–250 million per year (see Figure ES3). Just a handful of basic demand flexibility options—including air conditioning, domestic hot water heater timing, and electric vehicle charging—show significant capability to shift loads to lower-cost times (see Figure ES4), reduce peak demand (see Figure ES5), and increase solar PV on-site consumption (see Figure ES6). In Hawaii, electric dryer timing and battery energy storage also play a role in demand flexibility.

METHODOLOGY AND ASSUMPTIONS

We analyze the economics of demand flexibility for residential customers in two use cases across four total scenarios under specific, illustrative, real-world utility rate structures:

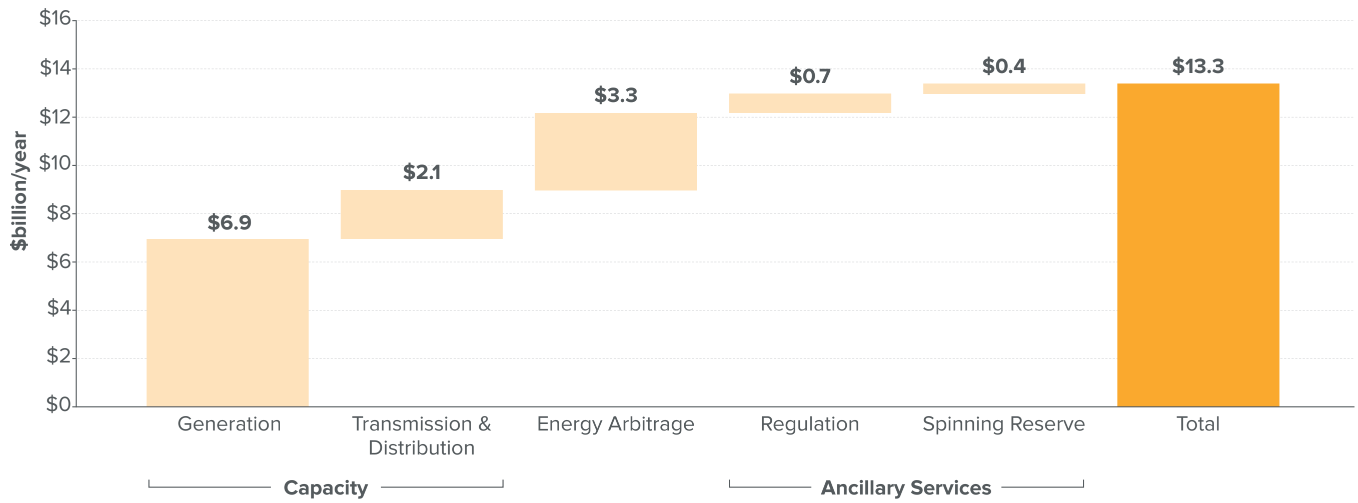
1. Provide bill savings by shifting energy use under granular utility rates
   a. Residential real-time pricing (Commonwealth Edison, Illinois (ComEd))
   b. Residential demand charges (Salt River Project, Arizona (SRP))
2. Improve the value of customer-focused distributed energy resource deployment
   a. Non-export option for rooftop PV (Hawaiian Electric Company (HECO)) *Proposed*
   b. Reduced compensation for exported PV (Alabama Power Company (APC))

We use detailed data on consumption patterns to calibrate models for demand shifting in different climates, seasons, and rate structures; and perform an economic analysis of five major demand-flexible residential loads:

- Air conditioning (AC)
- Domestic hot water (DHW)
- Electric vehicle (EV) charging
- Electric dryer cycle timing
- Battery energy storage

FIGURE ES2

ESTIMATED AVOIDED U.S. GRID COSTS FROM RESIDENTIAL DEMAND FLEXIBILITY



**Individual components do not add to total because of rounding*

FIGURE ES3

DEMAND FLEXIBILITY ANNUAL POTENTIAL BY SCENARIO

DF GENERATES SIGNIFICANT PER-CUSTOMER BILL SAVINGS (%) WITH LARGE AGGREGATE MARKET SIZES ($ FOR EACH ANALYZED UTILITY TERRITORY)

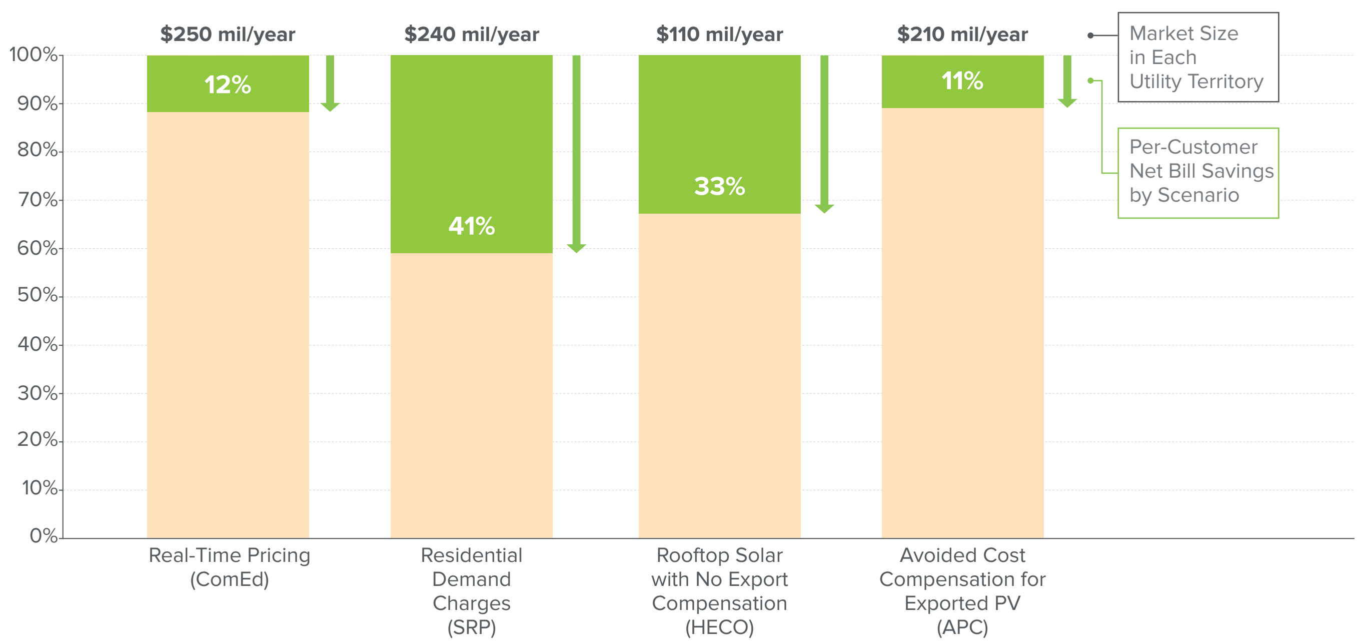


FIGURE ES4

SHIFTING LOADS TO LOWER-COST TIMES THROUGH DEMAND FLEXIBILITY (ComEd)

DF SHIFTS LOAD FROM HIGH-COST TO LOW-COST HOURS

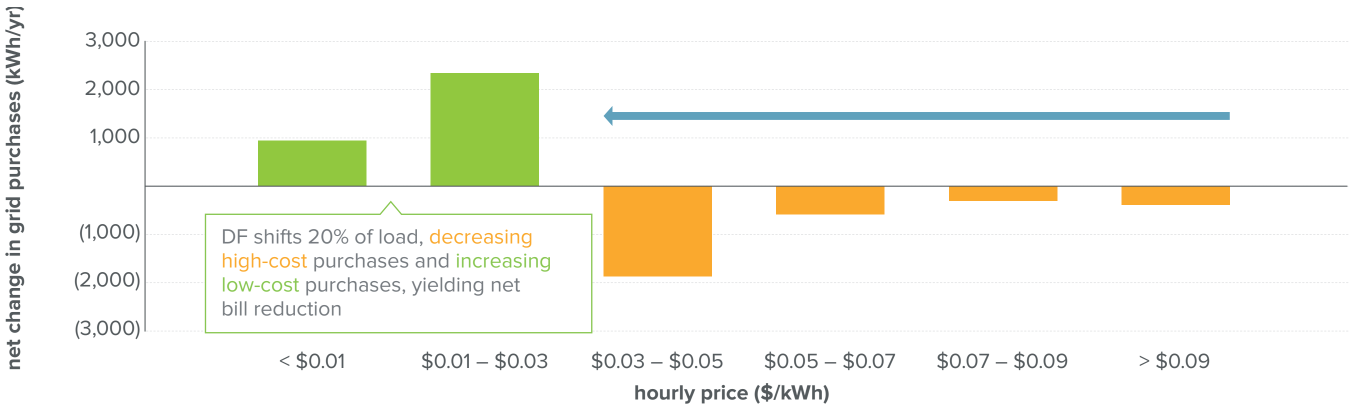


FIGURE ES5

REDUCING PEAK DEMAND THROUGH DEMAND FLEXIBILITY (SRP)

DF REDUCES PEAK CUSTOMER DEMAND BY COORDINATING LOAD TIMING TO MINIMIZE PEAKS

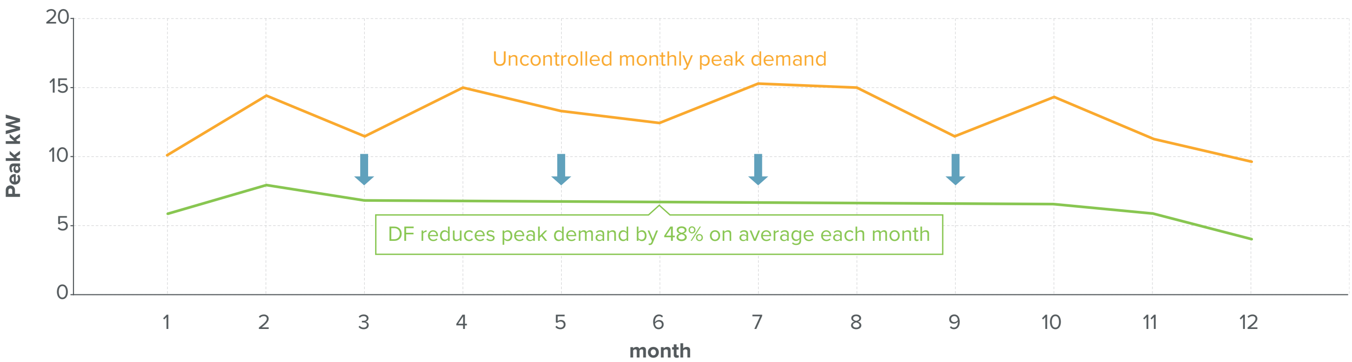
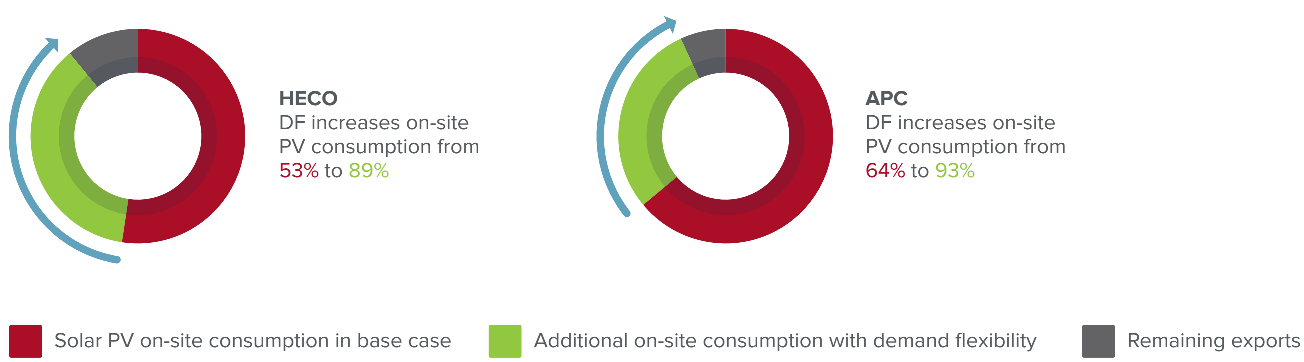


FIGURE ES6

INCREASING SOLAR PV ON-SITE CONSUMPTION THROUGH DEMAND FLEXIBILITY (HECO & APC)

DF SHIFTS LOAD TO COINCIDE WITH ROOFTOP PV PRODUCTION, INCREASING ON-SITE CONSUMPTION AND REDUCING EXPORTS



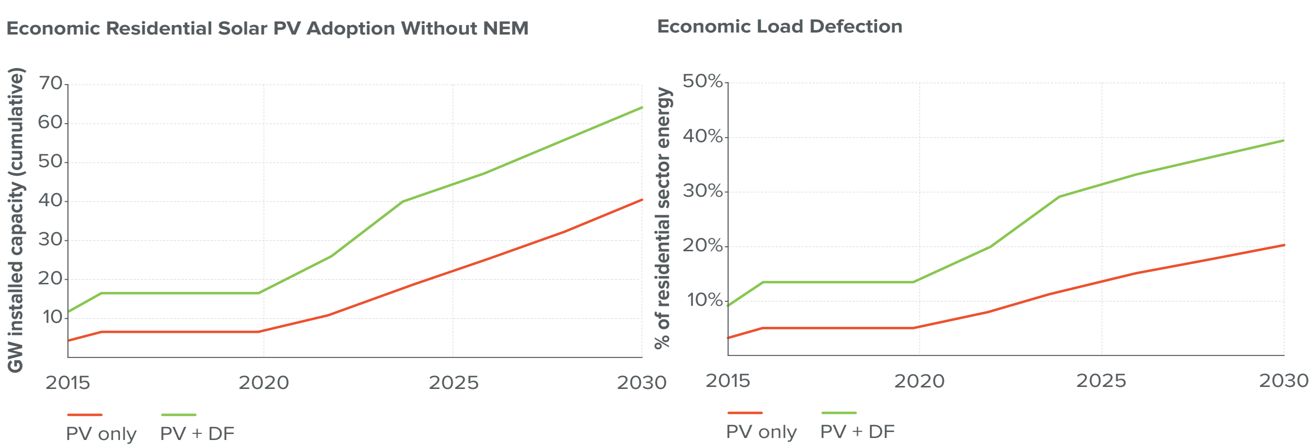
Utilities should see demand flexibility as a resource for grid cost reduction, but under retail rates unfavorable to rooftop PV, demand flexibility can instead hasten load defection by accelerating rooftop PV's economics in the absence of net energy metering (NEM).

Some utilities and trade groups are considering or advocating for changes to traditional net energy metering arrangements that would compensate exported solar PV at a rate lower than the retail rate of purchased utility energy (similar to the avoided cost compensation case discussed above). We build on the analysis presented in RMI's *The Economics of Load Defection* and show that, if export compensation for solar PV were eliminated or reduced to avoided cost compensation on a regional scale in the Northeast United States, DF could improve the economics of non-exporting solar PV, thus dramatically hastening load defection—the loss of utility sales and revenue to customer-sited rooftop PV (see Figure ES7).

FIGURE ES7

NORTHEAST U.S. RESIDENTIAL SOLAR PV MARKET POTENTIAL WITH AND WITHOUT DEMAND FLEXIBILITY

ASSUMING ROOFTOP PV RECEIVES EXPORT COMPENSATION AT AVOIDED COST, DF ACCELERATES THE PV MARKET AND LOAD DEFECTION



IMPLICATIONS

Demand flexibility represents a large, cost-effective, and largely untapped opportunity to reduce customer bills and grid costs. It can also give customers significant ability to protect the value proposition of rooftop PV and adapt to changing rate designs. Business models that are based on leveraging flexiwatts can be applied to as many as 65 million customers today that have access to existing opt-in granular rates, with no new regulation, technology, or policy required. Given the benefits, broad applicability, and cost-effectiveness, the widespread adoption of DF technology and business models should be a near-term priority for stakeholders across the electricity sector.

Third-party innovators: pursue opportunities now to hone customer value proposition

Many different kinds of companies can capture the value of flexiwatts, including home energy management system providers, solar PV developers, demand response companies, and appliance manufacturers, among others. These innovators can take the following actions to capitalize on the demand flexibility opportunity:

1. Take advantage of opportunities that exist today to empower customers and offer products and services to complement or compete with traditional, bundled utility energy sales.
2. Offer the customer more than bill savings; recognize that customers will want flexibility technologies for reasons other than cost alone.
3. Pursue standardized and secure technology, integrated at the factory, in order to reduce costs and scale demand flexibility faster.
4. Partner with utilities to monetize demand flexibility in front of the meter, through the provision of additional services that reduce grid costs further.

Utilities: leverage well-designed rates to reduce grid costs

Utilities of all types—vertically integrated, wires-only, retail providers, etc.—can capture demand flexibility's grid value by taking the following steps:

1. Introduce and promote rates that reflect marginal costs, in order to ensure that customer bill reduction (and thus, utility revenue reduction) can also lead to meaningful grid cost decreases.
2. Consider flexiwatts as a resource for grid cost reduction, and not solely as a threat to revenues.
3. Harness enabling technology and third-party innovation by coupling rate offerings with technology and new customer-facing business models that promote bill savings and grid cost reduction.

Regulators: promote flexiwatts as a least-cost solution to grid challenges

State regulators have a role to play in requiring utilities to consider and fully value demand flexibility as a low-cost resource that can reduce grid-level system costs and customer bills. Regulators should consider the following:

1. Recognize the cost advantage of demand flexibility, and require utilities to consider flexiwatts as a potentially lower-cost alternative to a subset of traditional grid infrastructure investment needs.
2. Encourage utilities to offer a variety of rates to promote customer choice, balancing the potential complexity of highly granular rates against the large value proposition for customers and the grid.
3. Encourage utilities to seek partnerships that couple rate design with technology and third-party innovators to provide customers with a simple, lower cost experience.

INTRODUCTION

01

INTRODUCTION

THE GROWING GRID INVESTMENT CHALLENGE

The United States electric grid will need an estimated $1–1.5 trillion of investment in the next 15 years, assuming no change in how it's planned and run. This includes $505 billion in generation resources, nearly $300 billion in transmission, and more than $580 billion in distribution assets.[2] These investments will partly correct years of underinvestment.[3]

Historically, power-system investments have been recovered from residential and small-commercial customers in mostly volumetric, bundled charges assessed per kilowatt-hour (kWh). This was acceptable when electricity consumption grew by an average 4.6% per year from 1950 to 2010, but that demand growth has stagnated. U.S. electricity retail sales to ultimate customers peaked in 2007 and have drifted down ever since,[4] falling in five of the past seven years. The U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2015* projects demand growth of 0.8% per year through 2040, with residential usage growing just 0.5%.

Moreover, while total retail sales overall are flat or falling, both peak demand and the ratio of peak to average demand have been rising across most of the country.[5] This creates a significant challenge: How to pay for the grid's needed investment when sales are stagnating? And will the grid require as much investment as forecasts suggest, or might there now exist another path based on new opportunities?

The growth of peak demand could justify infrastructure upgrades, including construction of combustion turbines that may operate expensively for just a few hours per year to meet peak demand.[6] But investment required for new infrastructure and to maintain and replace aging infrastructure cannot be sustainably recovered in an era of stagnant electricity sales, especially not without raising retail prices under current volumetric rate structures for residential customers.[7] Those prices have been steadily climbing and official forecasts anticipate further increases,[8] encouraging efficiency and hence further demand reduction. Without positing that these trends might create a "death spiral" of rising price and falling demand, one can still easily see the seeds of worrisome contradictions in current U.S. electricity trends.

THE RISE OF DISTRIBUTED ENERGY RESOURCES

Meanwhile, the grid—and customers' relationship with it—are changing in big ways that offer an alternative to the massive expansion of large, centralized generation, transmission, and distribution assets. A growing range of customer-sited distributed energy resources (DERs)—including low-cost distributed generation, load control, energy storage, and end-use efficiency—offer electricity customers new choices for how and when to consume and even generate electricity. Collectively, these new resources can complement, compete with, and perhaps even displace the ~1,000 GW of existing centralized generators and their grids.

In many cases, behind-the-meter DERs can mitigate these investment needs at much lower total cost. However, utilities and regulators are inconsistent in accounting fully for the costs and benefits of DERs, so many utilities continue to emphasize traditional generation and transmission and distribution investments.[9] Meanwhile, customers and third-party providers will probably continue investing in behind-the-meter energy solutions at unprecedented rates.[10] This threatens a vicious cycle of over-investment and duplication of resources on both sides of the meter.

REVISITING ASSUMPTIONS ABOUT ELECTRICITY SUPPLY AND DEMAND

Yet utility and customer investments on both sides of the meter are based on a fundamental assumption that now requires significant revisiting: *balancing reliable generation (supply) to meet end-use demand based on inflexible demand profiles.* This asymmetrical view, where flexibility must come solely from the supply side, is no longer necessary or helpful, thanks to a new kind of resource that makes the demand side highly flexible too. *Demand flexibility (DF)* evolves and expands the capability behind traditional demand response (DR) programs. DF allows demand to respond continuously to changing market conditions through price signals or other mechanisms. DF is proving a grossly underused opportunity to buffer the dynamic balance between supply and demand. When implemented, DF can create quantifiable value (e.g., bill savings, deferred infrastructure upgrades) for both customers *and* the grid.

While DF's capability is not new, three trends make now the right time to seize its benefits: a) communications and control technologies have become cheap, powerful, and ubiquitous; b) utility rate structures are becoming sufficiently granular (e.g., real-time pricing, residential demand charges), and c) business models are emerging and maturing that can deliver DF along with other highly attractive customer value propositions (e.g., rooftop PV bundled with energy management software).

DEMAND FLEXIBILITY DEFINED

Demand flexibility uses communication and control technology to shift electricity use across hours of the day while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality but lower cost.

Demand flexibility combines two core elements:

1. It applies automatic control to reshape a customer's demand profile continuously in ways that either are invisible to the customer (e.g., decoupling the timing of grid-use from end-use through storage) or minimally affect the customer (e.g., shifting the timing of non-critical loads within customer-set thresholds).
2. For grid-connected customers, it leverages more-granular rate structures (e.g., time-of-use or real-time pricing, demand charges, distributed solar PV export pricing) to provide clear retail price signals—either directly to customers or through third-party aggregators—that monetize DF's capability to reduce costs for both customers and the grid.

Importantly, DF need not complicate or compromise customer experience. Technologies and business models exist today to shift load seamlessly while maintaining or even improving the quality, simplicity, choice, and value of energy services to customers.

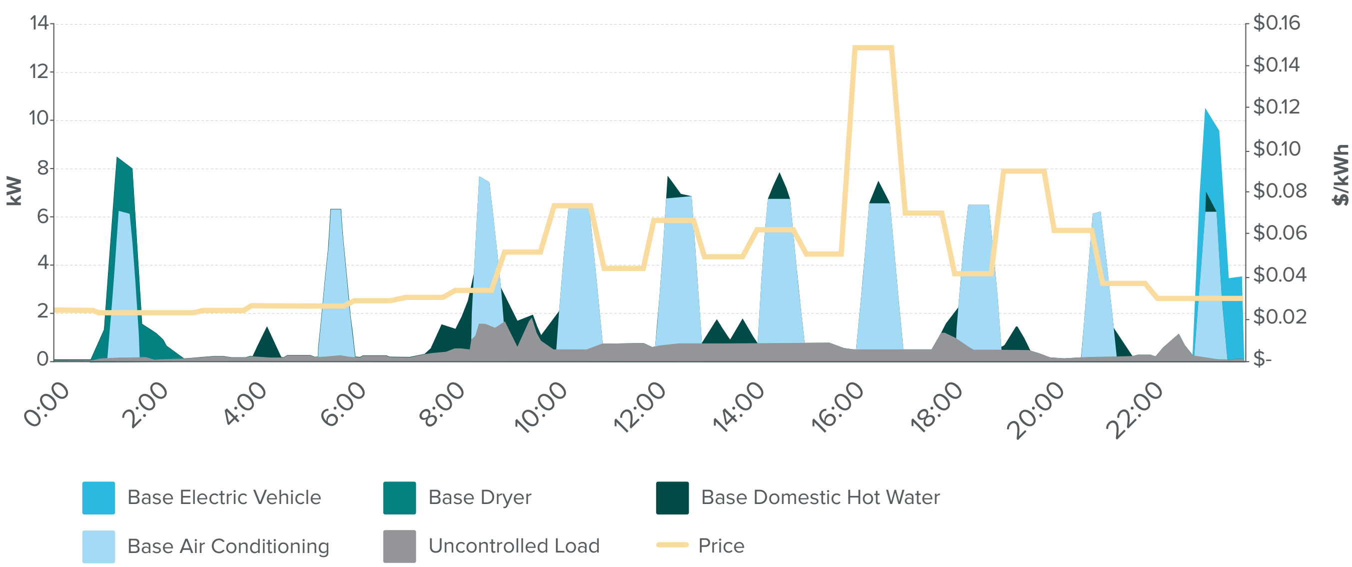
THE EMERGING VALUE OF FLEXIWATTS

Electric loads that demand flexibility shifts in time can be called *flexiwatts*—watts of demand that can be moved across the hours of a day or night according to economic or other signals. Importantly, flexiwatts can be used to provide a variety of grid services (see Table 2, page 17).

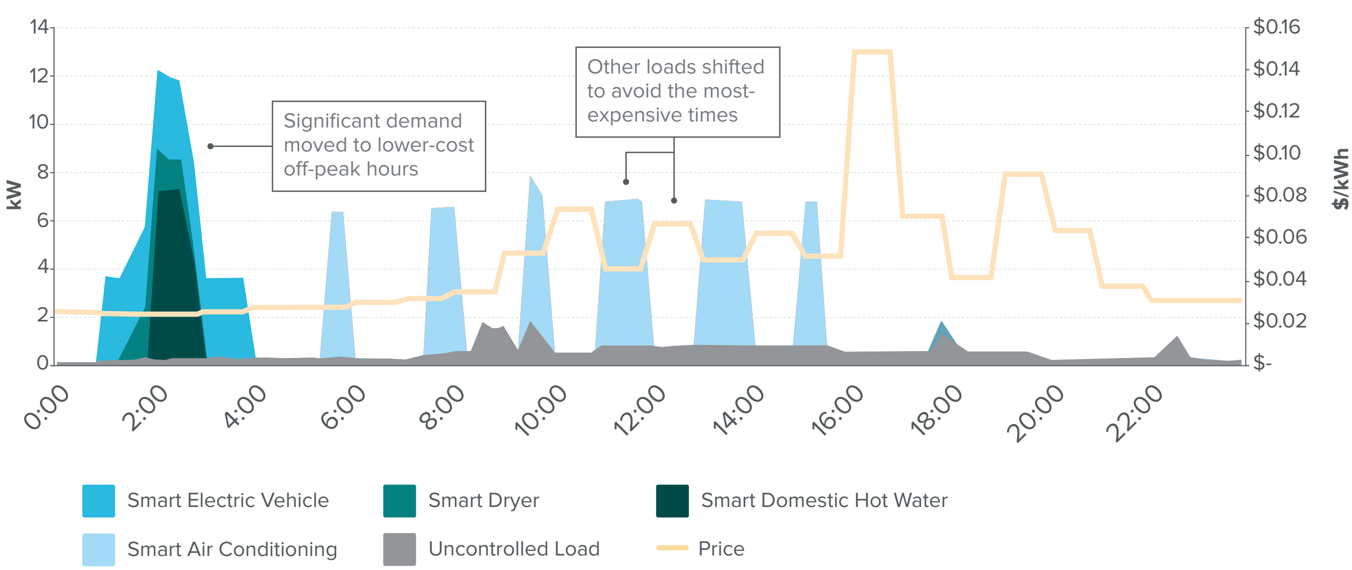
Demand flexibility is illustrated in Figure 1. In this example, customers pay dynamic, real-time prices for energy that change every hour. In the uncontrolled load case, appliance loads cycle on and off without regard for the time-varying price. In the demand flexibility case, many loads are shifted to the least-expensive hours, lowering a customer's bills and moving load away from grid peak. With enough participating customers, flexiwatts can be used to flatten the grid's aggregate demand profile, lowering overall system costs.

FIGURE 1

EXAMPLE BASE-CASE, UNCONTROLLED LOAD



EXAMPLE BASE-CASE, PRICE-OPTIMIZED LOAD PROFILE



DEMAND FLEXIBILITY AND DEMAND RESPONSE

The approach to using demand flexibility described in this paper relies on a similar capability underlying the current U.S. demand response industry, with $1.4 billion revenue in 2014 alone.[11] However, there are several important distinctions (see Table 1), including a customer-centric business model that relies on granular rates and customer bill management as opposed to a reliance on bilateral contracts or wholesale market participation. This facilitates a more continuous reshaping of loads, which in turn broadens the potential grid benefits. It also potentially offers a faster path to scalability than one that relies on centrally managed programs.

The current paradigm of demand response is focused on providing traditional generation services with flexible demand. In contrast, demand flexibility can offer a broader value proposition that is customer-focused. By relying on direct customer bill savings and seamless technology, customer-focused DF models offer a distinct path towards a continuous, grid-interactive flexibility resource that is complementary to the existing DR paradigm. By responding to retail price signals that are present every day, DF can be a full-time resource for lowering energy costs, integrating renewable energy, and reducing peak-period demand. There is growing industry recognition, including from state regulators[12] among other stakeholders, that leveraging DF to expand beyond the existing demand response paradigm can lead to further cost reduction in addition to substantial customer value.

BOX 1
DEMAND RESPONSE'S UNCERTAIN FUTURE

The future of demand response (DR) is in question with a recent federal court decision on a key ruling, Order 745, from the Federal Energy Regulatory Commission (FERC). The U.S. Supreme Court is scheduled to take up the case in its 2015–2016 term; a key outcome will be whether the price paid to DR programs must be equivalent to prices paid to generators.[13]

This ruling will be immensely important for the future of a low-cost, societally beneficial resource. However, the debate around DR showcases how the current industry is limited by traditional, top-down grid paradigms. By focusing on DR's revenue potential in wholesale markets, a huge part of the core value proposition of demand flexibility is lost—namely, the economic benefits of flexible, controllable demand to individual customers. Table 1 highlights the differences between traditional DR and customer-focused models to capture the value of flexiwatts. DF can deliver DR's benefits and more, by different means, with different institutions and business models, so a diverse range of approaches can compete in whatever legal environment emerges.

TABLE 1
DEMAND RESPONSE AND DEMAND FLEXIBILITY

	DEMAND RESPONSE	DEMAND FLEXIBILITY
VALUE ENABLER/ REVENUE MODEL	Wholesale market signals; bilateral contracts	Granular, customer-facing retail rate design
TIMING	Infrequent—often reactionary and used only as a last resort during extreme grid peaking emergencies	Continuous—can be used proactively to reduce costs across all hours of the year
BUSINESS MODEL FOCUS	Utility/grid operator	Customer, with important impacts on grid operations
PRIMARY CUSTOMER VALUE PROPOSITION	Incentive payments	Direct bill reduction

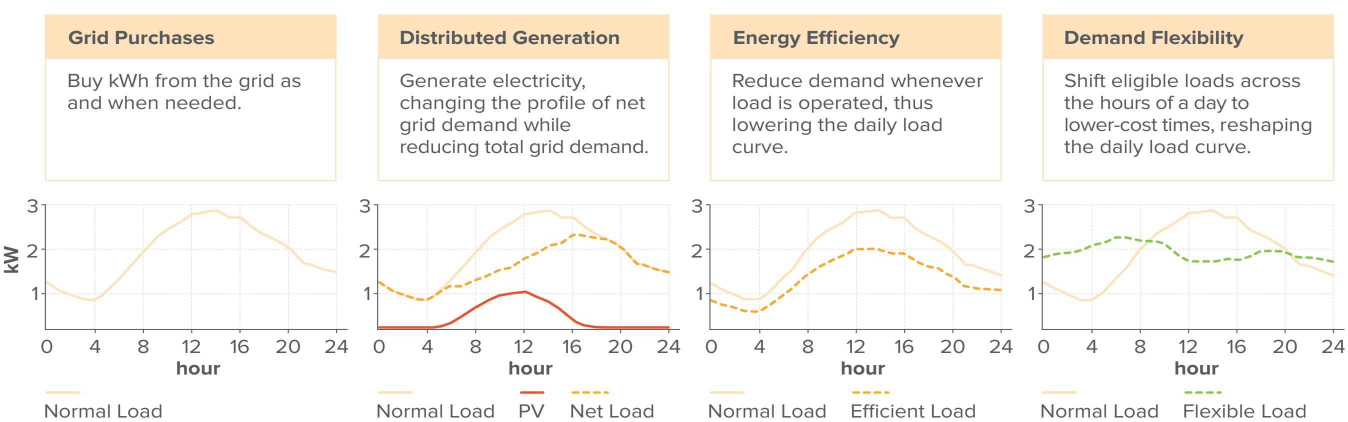
DEMAND FLEXIBILITY IN CONTEXT: THE BROADER OPPORTUNITY FOR DERs TO LOWER GRID COSTS

Customers have an increasing range of choices to meet their demand for electricity beyond simply purchasing it from the grid at the time of consumption. They also now have the opportunity to generate their own electricity through distributed generation, avoid the need for electricity through energy efficiency (i.e., negawatts), or shift the timing of consumption through demand flexibility (i.e., flexiwatts). All four of these options need to be evaluated holistically in order to minimize costs for customers *and* the grid (see Figure 2).

TABLE 2
FUNDAMENTAL VALUE DRIVERS OF DEMAND FLEXIBILITY

CATEGORY	DEMAND FLEXIBILITY CAPABILITY	GRID VALUE	CUSTOMER VALUE
Capacity	Can reduce the grid's peak load and flatten the aggregate demand profile of customers	Avoided generation, transmission, and distribution investment; grid losses; and equipment degradation	Under rates that price peak demand (e.g., demand charges), lowers customer bills
Energy	Can shift load from high-price to low-price times	Avoided production from high-marginal-cost resources	Under rates that provide time-varying pricing (e.g., time-of-use or real-time pricing), lowers customer bills
Renewable energy integration	Can reshape load profiles to match renewable energy production profiles better (e.g., rooftop PV)	Mitigated renewable integration challenges (e.g., ramping, minimum load)	Under rates that incentivize on-site consumption (e.g., reduced PV export compensation), lowers customer bills

FIGURE 2
GRID PURCHASES, DISTRIBUTED GENERATION, ENERGY EFFICIENCY, AND DEMAND FLEXIBILITY COMPARED



A LANDSCAPE OF EVOLVING RESIDENTIAL RATE STRUCTURES

In light of technological innovation and changing grid costs, utilities, regulators, legislators, and DER providers are all rethinking rate structures for mass-market customers. Each group, with both overlapping and opposing agendas, has proposed a variety of new rate design modifications. We see several key trends emerging in residential rate design discussions around the country, with varying implications for DF's value (see Table 3).

These four rate design trends are highly contentious. Offering real-time pricing to residential customers on an opt-in basis is the least controversial, as it allows customers who wish to respond to changing prices to do so. Residential demand charges have faced criticism because, in some implementations, they may not accurately reflect utility costs if they are assessed based on individual peak demand rather than on system peak hours.[30] Utilities and others advocating reduced compensation for exported PV argue that excessive grid export from rooftop PV may lead to grid stability issues,[31] but in utility jurisdictions without high PV adoption levels, limiting export compensation may encourage consumers to increase consumption during afternoon hours when energy prices (and solar PV generation) are typically high, unnecessarily raising system costs and losses.[32]

Finally, increased fixed charges are perhaps the most controversial proposals to change traditional rate designs. As fixed charges increase (and energy charges decrease), customer incentives to conserve or to self-generate electricity are reduced, limiting customers' ability to manage their bill and reduce system costs.[33] The considerations around high fixed charges versus alternatives that incent customers to reduce costs are discussed in our findings and implications.

TABLE 3
FOUR EMERGING TRENDS IN UTILITY RATE DESIGN WITH DEMAND FLEXIBILITY IMPLICATIONS

RATE TREND	DEMAND FLEXIBILITY IMPLICATIONS	UTILITY EXAMPLES
Time-varying Energy Pricing	Time-varying energy prices change, as the name implies, based on the time of day. Prices can change as rarely as 12-hour peak/off-peak blocks, or as frequently as every hour, providing incentive for customers to manage load in response to fluctuations in wholesale energy market prices. The most granular form of time-variant pricing—real-time pricing (RTP)—represents an evolution in sophistication compared to traditional time-of-use (TOU) rates. Over 4 million American households have adopted time-varying pricing,[14] and more than 21,000 households have adopted real-time pricing.[15]	Commonwealth Edison,[16] Ameren Illinois,[17] California IOU default TOU[18]
Residential Demand Charge	Demand charges, already common for commercial and industrial customers and gaining popularity in residential rates, typically impose a charge in proportion to the peak demand for a customer each month. The addition of a price signal for peak demand incents customers to smooth load to reduce grid impact and monthly bills.[19]	Salt River Project,[20] Arizona Public Service,[21] Westar Energy[22]
Reduced Compensation for Exported PV	Certain utilities currently offer or are considering modifications to traditional net energy metering policies to offer compensation for exported rooftop PV energy at the utility's avoided energy cost (typically less than half of the full retail cost) or another, reduced level (such as the cost of utility-scale solar). This creates an incentive to increase on-site solar PV consumption, since PV energy consumed is essentially valued at the higher retail rate rather than solar exported at the lower reduced compensation rate.	Alabama Power,[23] Xcel Energy CO (proposal),[24] Tucson Electric Power (proposal)[25]
Increased Fixed Charges	Many utilities have proposed increasing the fixed monthly customer charge, and reducing the variable energy charge, paid by customers. Increased fixed charges provide no incentive for customers to employ DF to reduce bills or system costs.	Madison Gas & Electric,[26] We Energies,[27] Wisconsin Public Service,[28] Kansas City Power & Light[29]

DEMAND FLEXIBILITY DOES NOT REQUIRE INCREASED COMPLEXITY FOR CUSTOMERS

More-granular rates that better align grid costs with customer prices can help fully capture demand flexibility's value, but increased granularity does not necessarily require increased complexity in the customer experience. Third parties (or utilities) can offer customers services in order to simplify the experience of responding to these rates. For example, there are already successful examples of customer-facing programs that automate appliance response to grid signals without requiring customer intervention,[34] and major solar companies have already announced plans to offer customers PV-integrated home energy management solutions.[35]

Indeed, granular rates can and should be developed in concert with technology and business model development by third-party providers; doing so would minimize the lag between a new rate and the technology to benefit from it, reduce uncertainty around revenue changes from the introduction of new rates, and ensure that a simple customer experience is available.

In the analysis that follows, we assess the underlying economics of DF from the customer perspective under more sophisticated rates, but recognize that innovative third-party business models are likely to help scale this market much faster by enabling seamless, automatic response and other values beyond cost savings, rather than relying on individual customer actions.

BOX 2

UTILITIES RECOGNIZE VALUE OF BEHIND-THE-METER FLEXIBILITY IN MITIGATING INFRASTRUCTURE COSTS

PSEG Long Island – Utility 2.0[36]

A DER product portfolio enables potential deferral of oil peaking generation

For PSEG Long Island, aging infrastructure and geographical constraints at the tip of Long Island created an opportunity for DERs to potentially reduce, defer, or eliminate investment in oil-fired peaking generation. The utility may look particularly at the value of demand flexibility as one means to accomplish this. For example, PSEG may expand its demand response program to upgrade outdated air conditioning and pool pump load control equipment.[37] The utility indicates a phased approach offers customers and DER solution providers more time to continue to install and demonstrate the value of DERs, including DF technology, to potentially defer or eliminate part or all of the 125 MW load requirement.

Consolidated Edison – Brooklyn-Queens Demand Management Program[38]

A DER package including demand flexibility can reduce capital investment requirements

In July 2014, Consolidated Edison (ConEd) in New York City proposed the Brooklyn-Queens Demand Management Program as a DER-driven solution to address a 69 MW capacity deficiency at a substation serving neighborhoods in Brooklyn and Queens. The utility proposes to integrate $150 million in customer-sited DER solutions to help defer $700 million of traditional substation upgrade expenses that would otherwise be required. Demand flexibility can contribute to this cost deferral, but system peak during summer months often occurs during late evenings, indicating that ConEd must expand its existing demand response programs to capture flexibility from more end-uses and customers so that demand can be reduced for longer periods.

Hawaiian Electric Companies – Solar PV integration strategies

Demand flexibility from water heaters and other loads can address system issues with increased rooftop PV adoption

Hawaii is home to some of the highest concentrations of distributed PV in the United States, which has raised concerns surrounding the economic and technical integration of this resource into the island grids. For example, on the island of Molokai, daytime PV generation can at times reduce the system demand below the grid's minimum generation levels.[39] The utilities serving the islands have acknowledged that DF-enabled loads aligned with PV output may be an important resource as PV penetration grows, including pre-cooling homes or pre-heating water to increase daytime minimum load,[40] and are piloting technologies including grid-interactive water heaters to mitigate these and other issues with PV integration.[41]

SCENARIOS, METHODOLOGY, AND ASSUMPTIONS

2

SCENARIOS, METHODOLOGY, AND ASSUMPTIONS

SCENARIOS FOR DEMAND FLEXIBILITY ANALYSIS

We identify four utility territories across the United States that offer different rate structures across a wide range of climates, demographics, and technology potential (see Table 4). We focus on two core use cases for demand flexibility: 1) lowering customer bills by optimizing consumption in response to time-varying energy and demand pricing, and 2) increasing on-site consumption of rooftop PV in the absence of net energy metering (NEM).

The analyzed examples show DF's potential in the context of real or prospective market scenarios only. They are *not* an endorsement of the specific rate structures and/or utilities we examine. There is room for debate about the relative merits and specific design considerations of real-time pricing, demand charges, and on-site consumption incentives. We use these scenarios to demonstrate the economic value of DF today and demonstrate examples of the broad economic potential to deploy flexiwatts as rate structures evolve.

TABLE 4
RATE STRUCTURES EXAMINED IN THIS REPORT

USE CASE	RATE STRUCTURE ANALYZED
Lowering customer bills by optimizing consumption in response to time-varying energy and demand pricing	**1. Residential real-time pricing** *Utility Example:* Commonwealth Edison (ComEd) – Illinois[42] *Status:* Option for all customers ComEd offers a real-time pricing option to residential customers, where the hourly energy price charged to customers is derived from nodal prices paid by ComEd to the regional transmission operator, PJM. We analyze the potential cost savings of each controlled load, optimizing its demand profile in response to real-time prices.
	2. Demand charges for solar PV customers *Utility Example:* Salt River Project (SRP) – Arizona[43] *Status:* Mandatory for new PV customers SRP recently approved a rate plan for new PV customers that includes an additional fixed charge as well as a monthly peak demand charge. We analyze the value of each load in reducing the peak demand on the utility side of the customer meter.
Increasing on-site consumption of rooftop solar PV in the absence of net energy metering	**3. No compensation for exported PV proposal** *Utility Example:* Hawaiian Electric Co. (HECO) – Hawaii[44] *Status:* Proposed option for new PV customers In an April 2014 order, the Hawaii Public Service Commission directed HECO to propose changes to its interconnection procedures that would favor customers with non-exporting PV systems. We analyze the capability of DF to increase on-site consumption of rooftop PV generation when the value of exported generation is zero.
	4. Avoided cost compensation for exported PV *Utility Example:* Alabama Power (APC) – Alabama[45] *Status:* Mandatory for all PV customers Alabama Power offers solar PV customers export compensation at the utility's avoided energy cost, which is less than half the retail rate. As with the HECO scenario, we analyze the capability of DF to increase on-site consumption of rooftop PV generation.

METHODOLOGY AND ASSUMPTIONS

To develop baseline customer electricity usage models, we use 15-minute submetered home energy data from the Northwest Energy Efficiency Alliance (NEEA), collected between 2012 and 2013, to derive typical profiles for behavior-driven appliance use (e.g., hot water and electric dryers), as well as estimates for non-flexible load in a typical home (e.g., television, cooking, lights, etc.). We discuss in the following sections how we account for location-specific, weather-driven loads like heating and air conditioning in each scenario (see Appendix B for a more detailed explanation of this methodology).

To estimate rooftop solar PV production in the three scenarios in which solar is modeled, we use weather data with the National Renewable Energy Laboratory's (NREL) PVWatts hourly production modeling tool, and interpolate to a 15-minute resolution. We use NREL's System Advisor Model (SAM) with the state-specific assumptions listed in Appendix B to calculate levelized cost of third-party-owned rooftop PV in each applicable scenario geography.

Load modeling methodology

For this analysis, we model the potential for four major electricity loads to be shifted in time: air conditioning, electric water heaters, electric dryers, and electric vehicle charging. We also model dedicated battery storage as a point of comparison. We analyze the savings potential of shifting from high-cost times to low-cost times (or from outside a PV generation period to inside a PV generation period) based on the specific cost drivers for customers in each modeled scenario: hourly price, peak demand, and PV output. Appendix C has a detailed description of the appliance- and rate structure-specific models used to minimize costs.

We model demand flexibility for each appliance over a full year in 15-minute increments in order to capture the impacts of changing weather, energy consumption, and solar PV production on the value of demand flexibility, as well as to capture the billing interval duration over which peak demand charges are assessed (30-minute for SRP, 60-minute for ComEd).

Each flexible load has different customized constraints and operating requirements:

- **Domestic electric hot water (DHW):**[i]
  We shift energy consumption by heating water in the storage tank preferentially during low-cost periods and ensuring that both a) enough hot water is present in the tank during high-cost periods so that the heating elements do not have to run, and b) there is always enough hot water in the tank to provide hot water under the same schedule to the customer as in the base uncontrolled case, for every daily profile of hot water use.

- **Air conditioning (AC):**
  We use a thermal model of a typical single-family home to derive a baseline AC consumption profile for each modeled geographic location. Modeled thermal loads include ambient air temperature-driven envelope heating as well as solar heating gains through windows, calculated using weather data and building energy modeling tools. To simulate smart controls, we impose a thermostat control strategy that pre-cools the building during low-cost periods and allows the building setpoint to rise up to 4°F during high-cost periods.[ii]

- **Electric vehicle (EV) charging:**
  We assume base-case drivers recharge EV batteries using a Level 1, 3-kW charger immediately upon returning from a 30-mile trip each day, with trip timing changing on weekdays (8:00 a.m. to 6:00 p.m.) versus weekends (8:00 p.m. to 11:00 p.m.). In other words, the car is unavailable for charging during the day on weekdays or on weekend evenings. In the controlled case, we optimize EV charging to occur at the least-cost hours when the vehicle is parked and plugged in, always charging to 100% by the time the driver next needs the car.

- **Electric dryers:**
  We use baseline dryer consumption profiles from the NEEA database. To optimize dryer load, we allow the start time of each cycle to shift by up to six hours in either direction to minimize total cycle costs. This can be accomplished either via behavioral change or via smart controls that allow a customer to load the dryer and delay cycle start time automatically.

As a point of comparison to demand flexibility, we model the capability of a dedicated 7 kWh/2 kW battery storage system in each of our use cases. We simulate the battery charging during low-cost hours and discharging during high-cost hours, subject to its inverter capacity and losses and its storage capacity.

[i] We restrict our analysis to homes with electric water heaters. EIA data indicate there are approximately 47 million residential electric water heaters in the U.S. as of 2009, representing 41% of the market.

[ii] Though we model this setpoint increase during all high-cost hours, our algorithm minimizes the actual temperature rise that takes place, and the savings presented here can be achieved with a very low number of high-temperature events (see Appendix C for a fuller description).

Cost assumptions

We use estimates of incremental technology capital costs (see Table 5). All dollars presented in this paper are 2014 real dollars. Appendix B contains more detail on these technology cost estimates.

To arrive at a net incremental cost to make AC flexible, we estimate geography-specific heating bill savings from installing a smart thermostat (taken as 10% of the annual heating bill[46]) and crediting that savings against the thermostat's incremental cost (see Appendix B for full methodology). To model battery storage economics, we use the 2015 pricing of Tesla's 7 kWh/2 kW Powerwall product, adding an assumed $1,000 cost for the inverter only in the scenario (ComEd) where the building analyzed does not already have an inverter for the PV system.[47]

We recognize that in some cases (e.g., communicating real-time pricing to customers) DF may rely on a communication solution between utilities and customer loads and a solution to measure customer demand with more granularity. Technology to provide these solutions could include advanced metering infrastructure (AMI), Internet-connected home energy management systems, or other approaches. We do not directly include the costs of AMI or other non-appliance-specific technology to enable communication and load response in our analysis, because there are many options available for the solutions included in this report to rely on existing infrastructure, such as in-home wireless Internet, cellular networks, etc.[48] In addition, three of the four utility scenarios analyzed have or will soon have extensive AMI rollout (HECO is the exception, but is piloting AMI and seeking approval for broader deployment[49]),[50] and nationwide there are over 50 million AMI meters already deployed as of 2015.[51]

In assessing the cost-effectiveness of grid-facing demand response programs, analysts often account for "program costs" in order to compare total DR costs against traditional generation resources.[52] For the customer-facing solutions analyzed in this paper, we do not incorporate these costs in our calculations for several reasons:

- In some cases, the cost of control software necessary to achieve some savings may already be embedded in the device price and thus included in our cost assumptions presented in Table 5 (e.g., smart thermostats allow a customer to set programs to minimize energy costs and many EV charging interfaces allow customers to schedule charging timing).[53]

TABLE 5
COST ASSUMPTIONS

LEVER	TECHNOLOGY REQUIRED	INCREMENTAL COST	LIFETIME
Domestic hot water (DHW)	Smart controls and variable-power heating elements	$200	10 years
Air conditioning (AC)	Communicating and/or "smart" thermostat	$225 (see text for further explanation)	10 years
Dryer	Communicating and/or "smart" cycle delay switch	$500	10 years
Electric vehicle (EV) charging	Communicating and/or "smart" charge timing controls	$100	10 years
Battery	7 kWh/2 kW battery bank	$3,000 (see text for further explanation)	10 years
Solar PV*		$3.50/$W_{DC}$	25 years

* Not a DF lever, but costs modeled in appropriate scenarios

- To the extent that the bundled software does not already support the specific approaches we model in this analysis, we recognize that the approaches we use for more-dynamic control are relatively simplistic (see Appendix C), and implementing them with existing device software is likely a trivial programming change that would not add significant cost.
- We also note that solutions that depend on customer-driven and/or automated response to price signals may not have the utility overhead costs typical of centrally-managed programs, such as traditional emergency demand response programs.

We recognize that investments in energy efficiency, alone or combined with DF technologies, are likely to be a part of the minimum-cost technology bundle for customers under any of the rate structures analyzed, and that efficiency has a commensurately great potential for grid cost reductions.[54] However, we focus our analysis on DF alone, in order to highlight its unique capabilities and economic value.

Market sizing assumptions

We extend the core modeling results for a single customer in each utility jurisdiction by scaling those results to estimate the savings potential, vendor market size, and PV market enabled for all eligible customers that could sign up for the rates we analyze. To scale our bill savings results to other customers served by the same utility, we first scale the consumption of our modeled customer to average residential consumption for each utility, using EIA Form 861 data from 2013. Similarly, for the capital costs of flexibility-enabling technology (i.e., controls and hardware), we scale the costs of cost-effective technology for our modeled customer to average consumption for residential customers.

For scenarios 2–4, where demand flexibility supports the value proposition of customers under PV-specific rates, we estimate the size of the PV market that DF could unlock. We estimate the number of single-family, owner-occupied homes that can support a PV system, and calculate the size of the PV installation market for these customers. Full methodology is outlined in Appendix D.

For scenarios 1 and 2, we estimate the utility-wide peak demand reduction potential unlocked by residential DF by scaling our peak demand savings estimate to average residential customer peak loads and the number of eligible customers (single-family, owner-occupied homes) by utility.[55]

The market size estimates we present are likely higher than the practical opportunity because many customers will not choose to adopt DF technologies even with strong economics. However, if even a fraction of the potential market adopts demand flexibility, it would still represent a large market opportunity for vendors to offer products and services that deliver bill savings to customers while lowering grid costs and improving grid operation.

In addition, the more customers that adopt DF, the more likely utilities are to react by refining offered rate structures to ensure that customer prices still reflect utility costs. For example, as more customers shift loads in response to real-time prices, it is likely to have an aggregate effect of smoothing the system load profile, and thus shrink the difference between peak and off-peak prices. Or, as more customers adopt technology to minimize peak demand, utilities may adjust demand charge magnitudes in order to true up cost recovery with expenses. The savings and market sizing results we present are thus reflective of current reality, but may change as utilities adjust rates.

BOX 3
HOW TO INTERPRET SUPPLY CURVES OF SHIFTED ENERGY

In this report, we use supply curves to illustrate the relative economics of different levers that can be used to achieve demand flexibility.

X-axis values (i.e., the width of the bar) represent the load-shifting potential for each lever, (i.e., how much load can be shifted in response to pricing signals). In calculating these results, we assume that all levers to the left have already been applied, in order to avoid double-counting shift potential. For three of our four cases, the units are kWh of shifted energy per year; for the fourth case that examines demand charge reduction, the x-axis units are monthly average kW of avoided peak demand.

Y-axis values (i.e., the height of each bar) represent the costs of achieving the load-shift for each lever. The values are calculated by dividing the fixed, annualized costs of each lever (i.e., hardware costs net of any incentives or savings; see Methodology section above) by the total shift value (either kWh/y or kW) of each lever, for units of $/(kWh/y) shifted or $/kW-mo avoided.

The horizontal dashed line represents the cost-effectiveness limit for flexibility. This limit is calculated differently for each case. Levers whose costs fall below this line are cost-effective; levers whose costs are above this line are not cost-effective at current hardware costs or utility rates (unless other values or use cases outside the scope of this analysis are also considered).

FIGURE 3
EXAMPLE SUPPLY CURVE OF DEMAND FLEXIBILITY

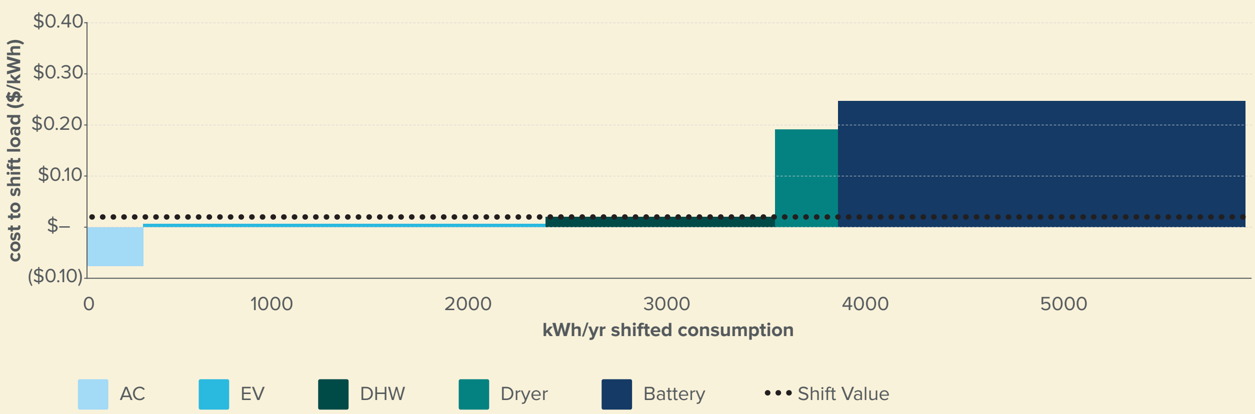


TABLE 6
HOW COST-EFFECTIVENESS LIMIT IS CALCULATED

CASE	COST-EFFECTIVENESS LIMIT
ComEd	Average achievable $/kWh difference between on- and off-peak electricity demand
SRP	Lowest tier of summer $/kW-month demand charges
HECO and Alabama Power	Difference between “buy” price (i.e., retail rate for energy purchased from utility) and “sell” price (i.e., compensation for exported PV energy)

FINDINGS

3

FINDINGS

Residential demand flexibility can help avoid up to $13 billion per year in grid costs

While the majority of this report focuses on the customer-facing value of demand flexibility, the grid-level cost savings potential that would accrue from massive deployment of DF should not be ignored. The total grid-level savings potential of business models built around customer-focused DF are equivalent to the total savings potential from traditional demand response programs; both models of load control and customer engagement can use the same underlying technologies to provide the same level of peak demand reductions and optimal timing of energy consumption. We estimate that total value to be approximately $13 billion per year (see Figure 4).

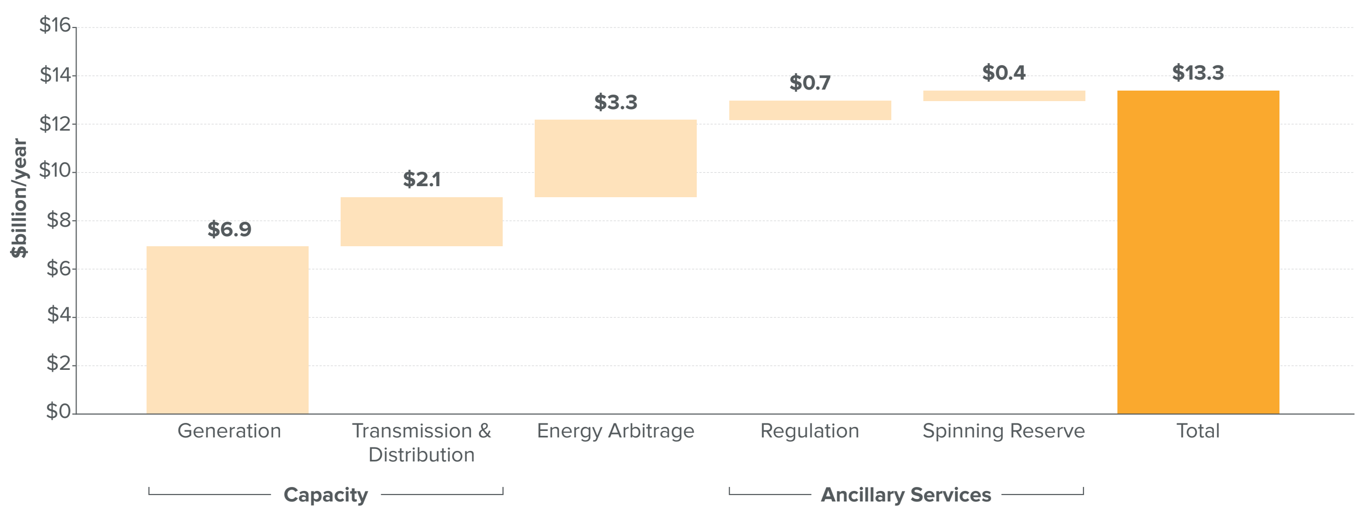
To estimate the system-level capacity, energy, and ancillary service benefits of controlling demand instead of supply, we update and expand on existing methodology proposed by analysts at the Brattle Group;[56] full methodology is outlined in Appendix A. We use detailed load models to estimate the coincident peak load reduction potential of optimizing the operating schedule of two common residential appliances across the United States—air conditioners and water heaters—and value those peak load reductions using conservative estimates of utilities' avoided costs for peak capacity for generation, distribution, and transmission. This yields a total avoided investment cost of approximately $9 billion per year.

Our estimate of peak load reduction potential—approximately 8% of total U.S. peak demand—is consistent with industry estimates of the potential of residential demand response,[57] and ignores the equivalently-sized potential from commercial and industrial customers.

To estimate the energy cost savings associated with shifting load in response to changing energy production costs, we analyze the potential of air conditioners, water heaters, and electric dryers to optimize their operating patterns against changing hourly prices in the seven organized energy markets in the U.S. Averaging savings across these markets and scaling to national appliance saturation rates, we find $3 billion per year of energy cost savings.

FIGURE 4

ESTIMATED AVOIDED U.S. GRID COSTS FROM RESIDENTIAL DEMAND FLEXIBILITY



Individual components do not add to total because of rounding

Building on recent research and pilot programs that highlight the capability of residential loads to provide ancillary services (spinning reserves and frequency regulation) at levels in excess of market needs,[58] we value the avoided cost potential (~$1 billion per year) if traditional generators are no longer required to provide these services.

The total number, $13 billion per year, represents the avoided cost potential at the grid level, without accounting for the investment in control hardware and software necessary to achieve these savings. The total $13 billion sum, then, can be thought of the as the combination of total grid cost savings and the net investment shifted away from traditional infrastructure and towards DF capabilities that lower customer bills (as explored in the following sections) in addition to lowering grid costs. The exact split between new investment required and net system benefits will depend on the cost trajectory of control hardware and software, as well as the success of business models seeking to capture this value. Likewise, the direct customer savings portion of this $13 billion total will depend on the nature of customer-facing business models and the particular evolution of retail rate structures.

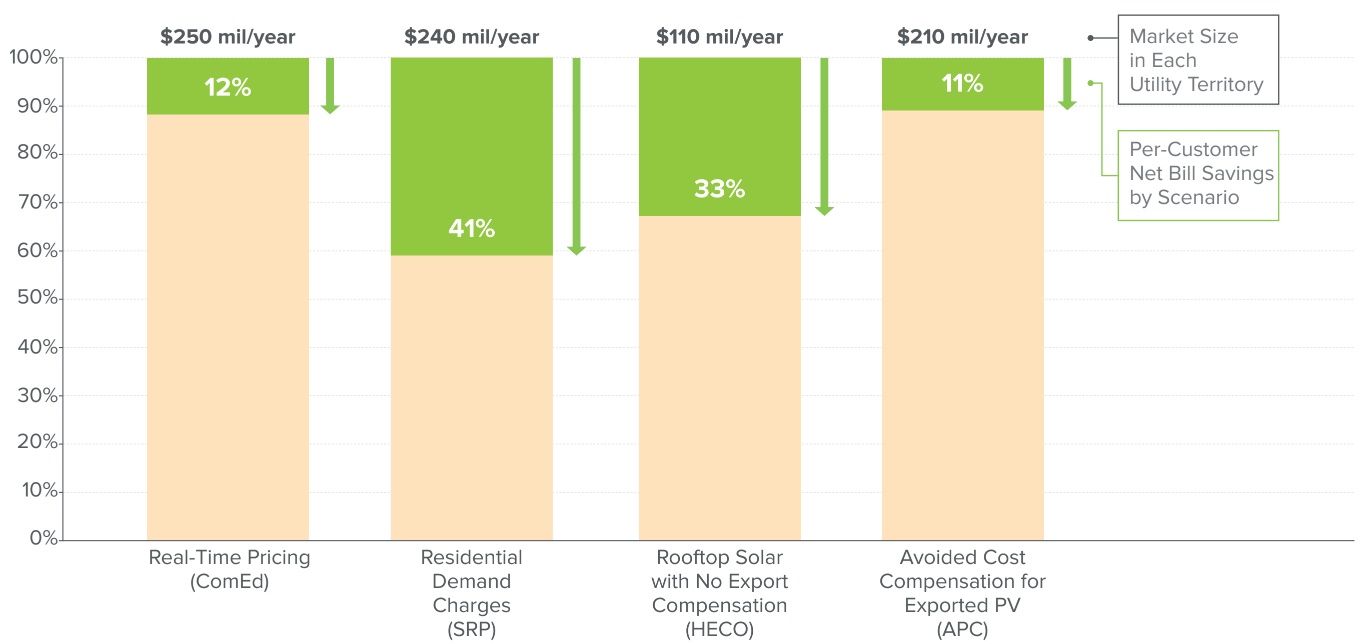
Demand flexibility offers substantial net bill savings of 10–40% annually for customers.

Using current rates across the four scenarios analyzed, demand flexibility could offer customers net bill savings of 10–40%. Across all eligible customers in each analyzed utility service territory, the aggregate market size (net bill savings) for each scenario is $110–250 million per year (see Figure 5). Just a handful of basic demand flexibility options—including air conditioning, domestic hot water heater timing, and electric vehicle charging—show significant capability to shift loads to lower-cost times (see Scenario 1: Real-Time Pricing), reduce peak demand (see Scenario 2: Residential Demand Charges), and increase solar PV on-site consumption (see Scenario 3: Non-Exporting Rooftop Solar PV Rate and Scenario 4: Avoided Cost Compensation for Exported PV). In Hawaii, electric dryer timing and battery energy storage also play a role in demand flexibility.

FIGURE 5

DEMAND FLEXIBILITY ANNUAL POTENTIAL BY SCENARIO

DF GENERATES SIGNIFICANT PER-CUSTOMER BILL SAVINGS (%) WITH LARGE AGGREGATE MARKET SIZES ($ FOR EACH ANALYZED UTILITY TERRITORY)



SCENARIO 1: REAL-TIME PRICING

Finding: Demand flexibility offers 19% savings on hourly energy charges, resulting in 12% net cost savings on overall bill

In 2007, Commonwealth Edison introduced a residential real-time pricing (RTP) program. Participating customers are given day-ahead estimates of hourly energy prices, and can adapt the timing of their consumption accordingly. The energy price actually paid by customers changes every hour to reflect the market-clearing price in the wholesale energy market. We analyze the cost savings that demand flexibility offers for both a customer already on this rate structure as well as a customer on the standard, volumetric rate who could choose to opt in to the real-time pricing rate.

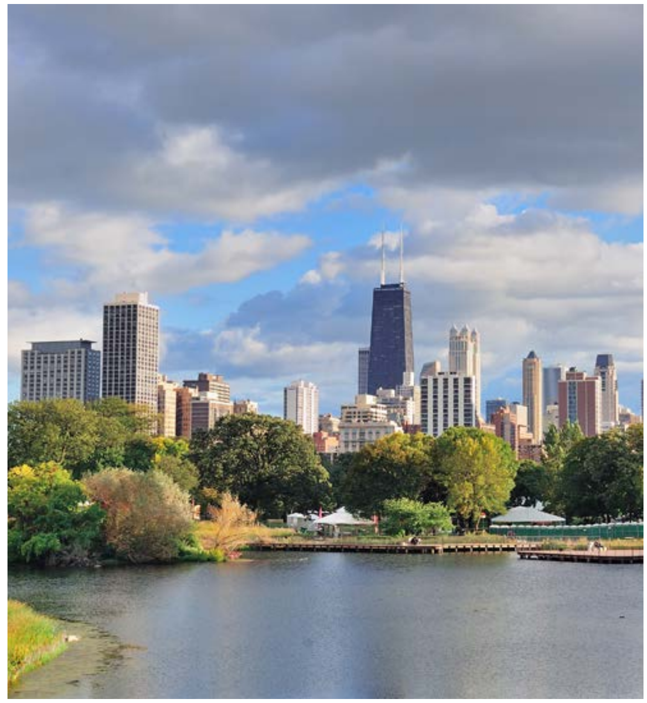


TABLE 7
SCENARIO-SPECIFIC MODELING SETUP: RESIDENTIAL REAL-TIME PRICING

VARIABLE	SCENARIO DETAIL
Utility	Commonwealth Edison (ComEd)
Program name/Rate design	Residential Real-Time Pricing[59] (opt-in program available to all customers)
Geography (TMY3 location)	Chicago, IL (O'Hare Airport)
Customers participating	Approximately 10,000
Fixed charges	$11.35/month
Demand charges	$4.05/kW-month (based on previous year's summer coincident peak)
Energy charges	Varies hourly; 2014 average $0.042/kWh. Additional distribution, etc. costs of $0.055/kWh also collected volumetrically.
Customer PV array size analyzed	None (no impact on results)

SCENARIO FINDINGS SUMMARY (ComEd)

- Cost-effective demand flexibility can **shift nearly 20% of total annual kWh** to lower-cost hours.
- Participating customers can **save $250/year, or 12% of total bills**, net of the cost of enabling technology.
    - Across all 10,000 existing, participating customers, this represents a **$1.3 million per year savings opportunity.**
    - There is a **$2.6 million investment opportunity** for innovative businesses to provide customers the products and services to unlock these savings (i.e., purchases of flexibility-enabling technology for EVs, A/C, and DHW—approximately $260/home).
- Customers on the default volumetric ComEd rate would **save up to $140/year, or 7% of total bills**, net of technology costs, if they switched to the real-time pricing rate and leveraged demand flexibility.
    - Across ComEd's 1.2 million customers, and the additional 2.3 million customers served by retail providers in ComEd's territory, this cost-effective switch represents a **net bill savings potential of up to $250 million per year.**
    - There is an **investment opportunity of up to $910 million** for vendors to help customers unlock these savings.
- If all eligible customers in ComEd territory pursued demand flexibility, the utility's **peak demand could be reduced by up to 940 MW.**

DETAILED FINDINGS

Load shifting potential

Cost-effective DF strategies can move about 20% of annual load from high-price hours to lower-price hours, with minimal impacts on comfort or convenience. A customer with an uncontrolled load profile would buy energy at an average of $0.044/kWh; with demand flexibility, that price declines nearly 19%, to $0.036/kWh.

Cost-effective flexibility bundle

In this scenario, three of the five technologies analyzed make up the most economic product bundle for customers. Smart thermostats to control air conditioning are the least-cost flexibility option: their cost of shifted energy is negative, due to the substantially lower heating cost (approximately $50/year in avoided gas costs) gained from installing a smart thermostat. EV charging is the next most cost-effective flexibility option at $0.01 per kWh of shifted load, as well as the overall largest shift opportunity, due to the low cost of enabling controls in EV charging equipment and the large flexibility potential of vehicle battery capacity. Domestic hot water is the third most cost-effective flexibility option, shifting more than half its energy demand into lower-cost hours. DF-capable dryers and on-site electric storage batteries, at current prices, do not appear cost-effective for real-time price arbitrage under this specific rate.

FIGURE 6

SHIFTING LOADS TO LOWER-COST TIMES THROUGH DEMAND FLEXIBILITY

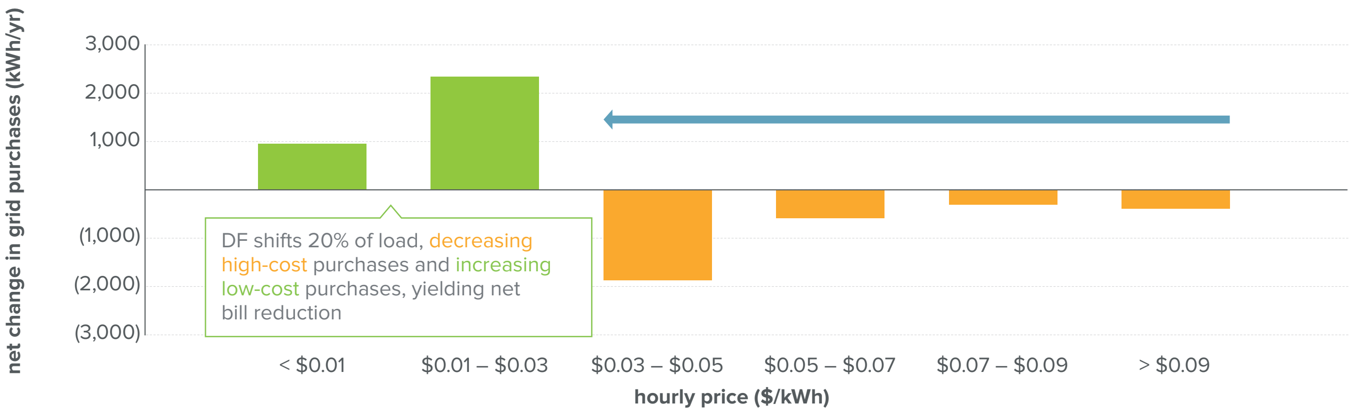


FIGURE 7

SUPPLY CURVE OF DEMAND FLEXIBILITY

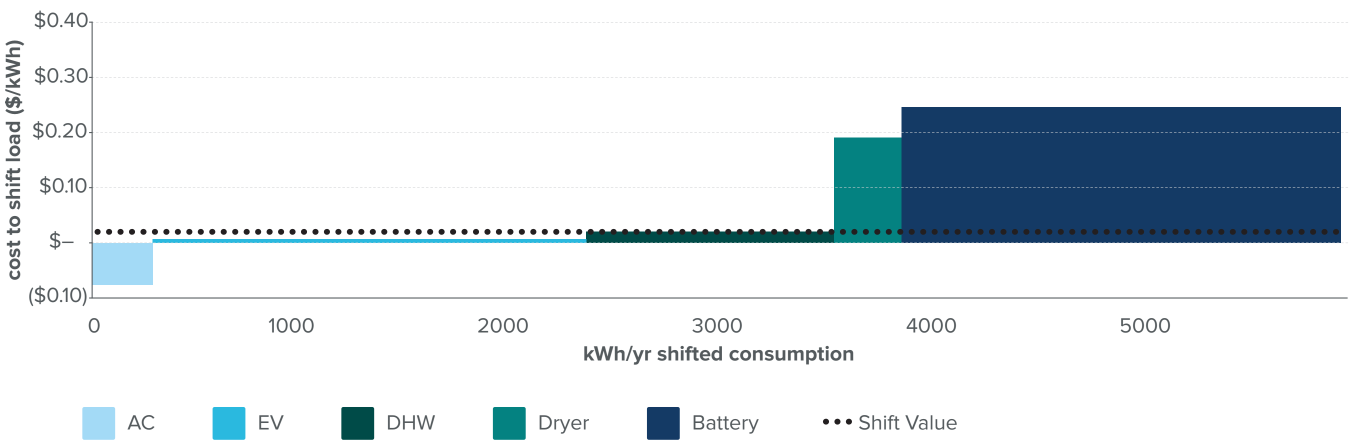
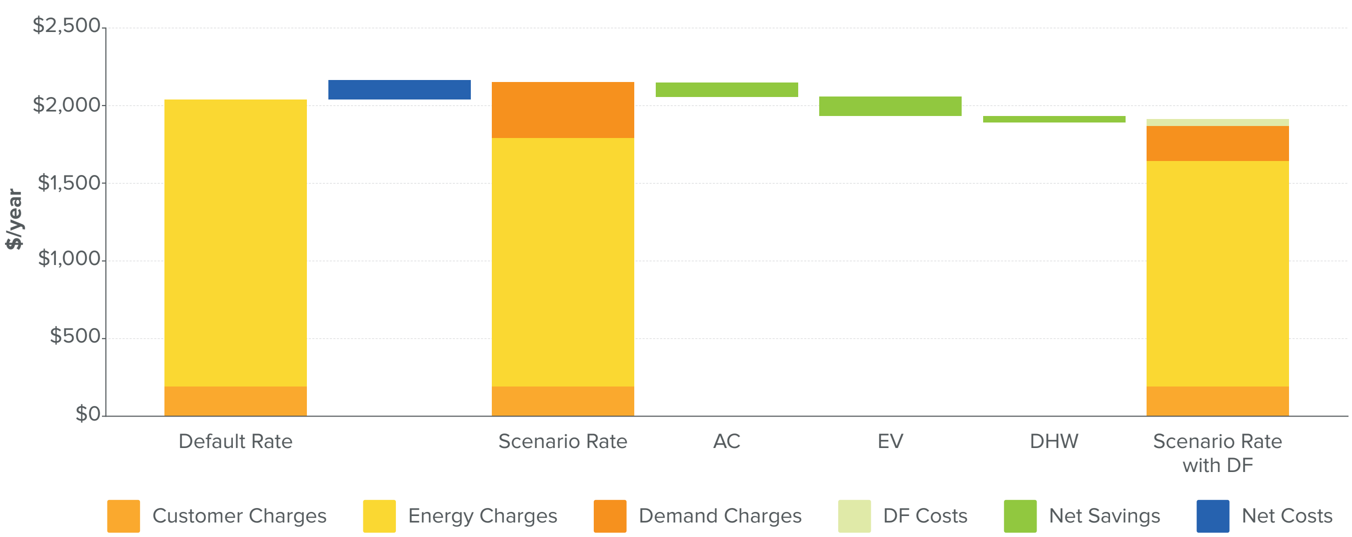


FIGURE 8

ANNUAL COST SCENARIOS FOR ComEd RESIDENTIAL CUSTOMER



Customer bill savings

For a customer on ComEd's default volumetric rate offering, switching to the RTP rate would increase bills by 5%, but leveraging flexiwatts under the RTP rate can lead instead to a 7% net savings. The combination of DF-enabled A/C, EVs, and DHW offer a potential net savings of $250/year, or 12% of the annual bill, for a customer already on the RTP rate. Much of the savings potential is driven by using energy in lower-cost hours, but there are also significant (35%) demand charge savings associated with moving energy to lower-cost hours, given ComEd's demand charge that is assessed during coincident peak hours when energy prices are also typically high.

Market sizing

Approximately 10,000 customers already on the real-time pricing rate within ComEd represent the existing market to capture these savings.[iii] The savings from currently participating customers could be up to $1.3 million per year, assuming similar potential across all enrolled customers; total savings potential may be smaller reflecting that customers on RTP already likely have adjusted their demand profile to reduce costs. However, the savings potential offered by DF could be used to recruit more of ComEd's 1.2 million bundled customers to the opt-in real-time pricing rate, or attract some of the 2.3 million customers served by competitive retail suppliers in ComEd's territory to sign up for ComEd service under the real-time rate. These customers represent a $250 million per year bill-saving potential. The investment in flexibility technologies to unlock these savings could be up to $910 million (i.e., purchases of flexibility-enabling technology for EVs, A/C, and DHW—approximately $260/home).

Smart thermostats and electric vehicles have demonstrated their customer appeal with certain segments even in the absence of granular rates. For example, Illinois has nearly 10,000 EVs on the road (most with access to residential real-time pricing in either the ComEd or Ameren service territories), and ComEd is one of at least 14 utilities nationwide that offer free or reduced-price Nest thermostats to customers in exchange for signing up for a specific program or rate structure.[60] Combining the existing value proposition of those products with the substantial savings offered by DF provides a business opportunity to increase the adoption of both.

[iii] There are also another ~10,000 customers on a similar real-time pricing program from neighboring utility Ameren Illinois.

SCENARIO 2: RESIDENTIAL DEMAND CHARGES

Finding: Demand flexibility can reduce monthly peak demand by 48%, lowering net bills by over 40%

Salt River Project (SRP) in Arizona has introduced a residential rate design option that imposes a charge dependent on the customer's peak 30-minute demand each month. This rate structure (currently being litigated) is required for customers installing new distributed generation capacity (e.g., rooftop PV). We analyze the economics of combining customer-sited PV with DF technologies to minimize peak-period demand and thus reduce utility bills for a customer on this rate, as well as for a non-PV customer who might install PV and move to this rate.

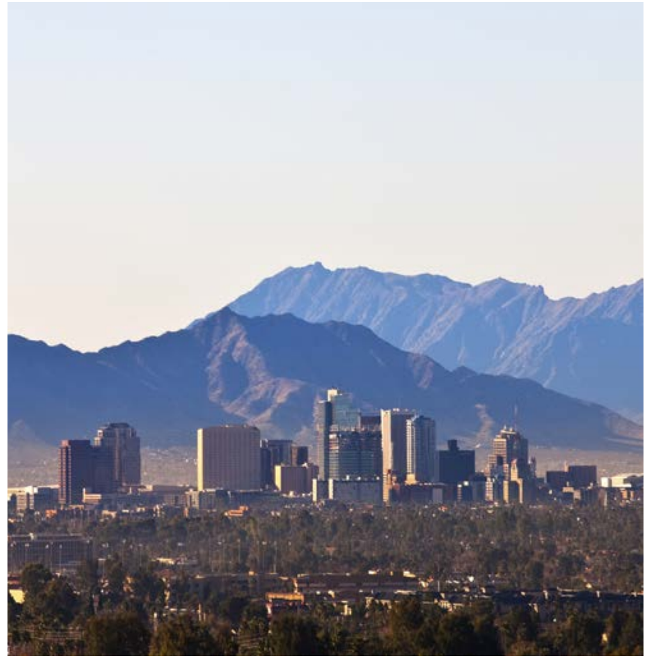


TABLE 8
SCENARIO-SPECIFIC MODELING SETUP: RESIDENTIAL DEMAND CHARGES

VARIABLE	SCENARIO DETAIL
Utility	Salt River Project (SRP)
Program name/Rate design	E-27 Customer Generation Price Plan[61] (mandatory for all new PV customers)
Geography (TMY3 location)	Phoenix, AZ (Sky Harbor Airport)
Customers participating	Fewer than 100 as of June, 2015;[62] 15,000 grandfathered solar PV customers under volumetric rates
Fixed charges	$20 for all customers plus $12.44 for new PV customers
Demand charges	Inclining block, varies by month from $3.55 to $34.19/kW-month between 3 blocks
Energy charges	Seasonal and peak period-specific, from $0.039 to $0.063/kWh
Customer PV array size analyzed	6 kW_{AC}—generates 50% of annual customer energy demand

SCENARIO FINDINGS SUMMARY (SRP)

- Cost-effective DF can **reduce peak demand by 48%** for a residential customer on average each month.
- Participating customers can **save $1,100/year, or 41% of total bills**, net of the cost of enabling technology.
- Demand flexibility **makes PV cost effective under SRP's new rate structure**.
    - Across all potential residential PV customers, there is a **net bill savings opportunity of up to $240 million per year.**
    - There is an **investment opportunity of up to $110 million** for vendors to help customers unlock these savings (i.e., purchases of flexibility-enabling technology for EVs, AC, and DHW—approximately $300/home).
    - This investment also unlocks a **residential rooftop PV market of up to 1.8 GW_{DC}** (**$6.3 billion of investment** at today's prices) in SRP territory, or 25% of SRP's 2013 peak load.
- If all eligible customers in SRP pursued DF, the utility's **peak demand could be reduced by up to 673 MW**.

DETAILED FINDINGS

Peak demand reduction potential

By coordinating the operation of major loads to avoid high peak demand during the 1–8 pm demand charge window, the combined control strategies are able to cost-effectively reduce peak demand by 48% on average each month.

Cost-effective flexibility bundle

Electric vehicle charging and AC thermostat control are the cheapest DF options, due to their substantial kW draws in the base case. DF in domestic water heating is also highly cost-effective, but the total demand reduction achieved is lower because DHW demand is not highly peak-coincident in SRP's territory. DF-enabled dryers and batteries, at current prices for DF technologies, do not appear cost-effective for demand charge mitigation under this specific rate, in part because the lower-cost flexibility from AC, EV charging, and water heating can mitigate the highest-tier demand charges.[iv]

Customer bill savings

For the modeled customer without PV on SRP's default residential rate, installing solar PV would automatically place them on the E-27 rate and increase total costs (including PV financing costs) by over 40%. However, our analysis finds that DF can reduce net bills under the E-27 rate by up to $1,100/year; these savings would allow a customer to install PV with a total service cost penalty of only 2% compared to full-service utility costs under the default rate.

[iv] In the case of dryers, a minimally invasive and easily accomplished behavior change—not running the dryer during weekday peak periods—could deliver some demand charge savings for zero incremental equipment costs; however to be conservative we do not account for this in the results.

FIGURE 9

MONTHLY PEAK DEMAND AND DEMAND CHARGE REDUCTIONS FOR SRP CUSTOMER

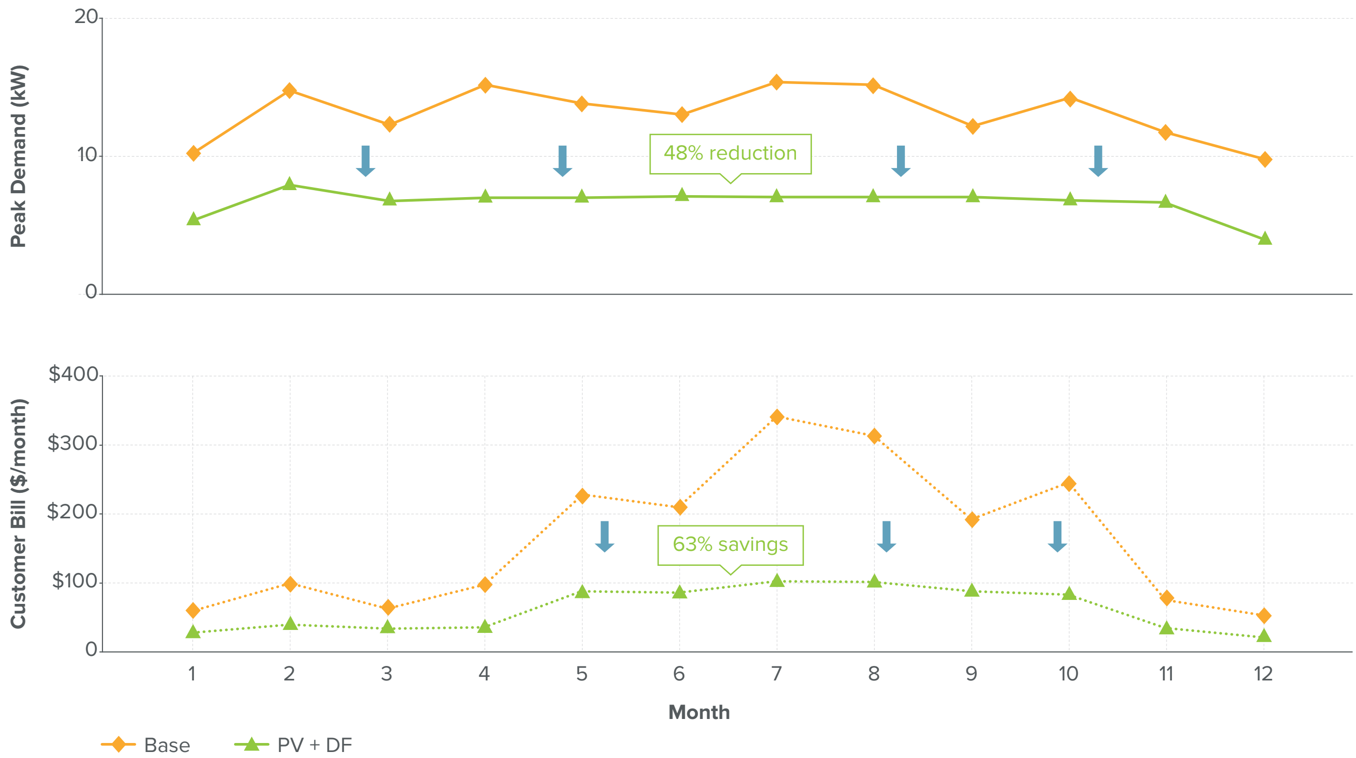


FIGURE 10

SUPPLY CURVE OF DEMAND FLEXIBILITY FOR SRP CUSTOMERS

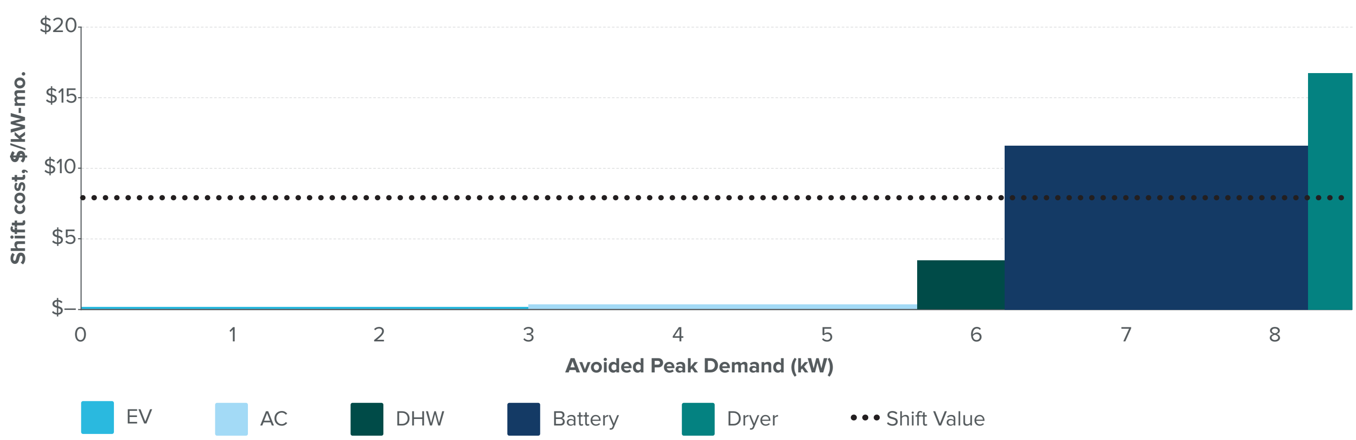
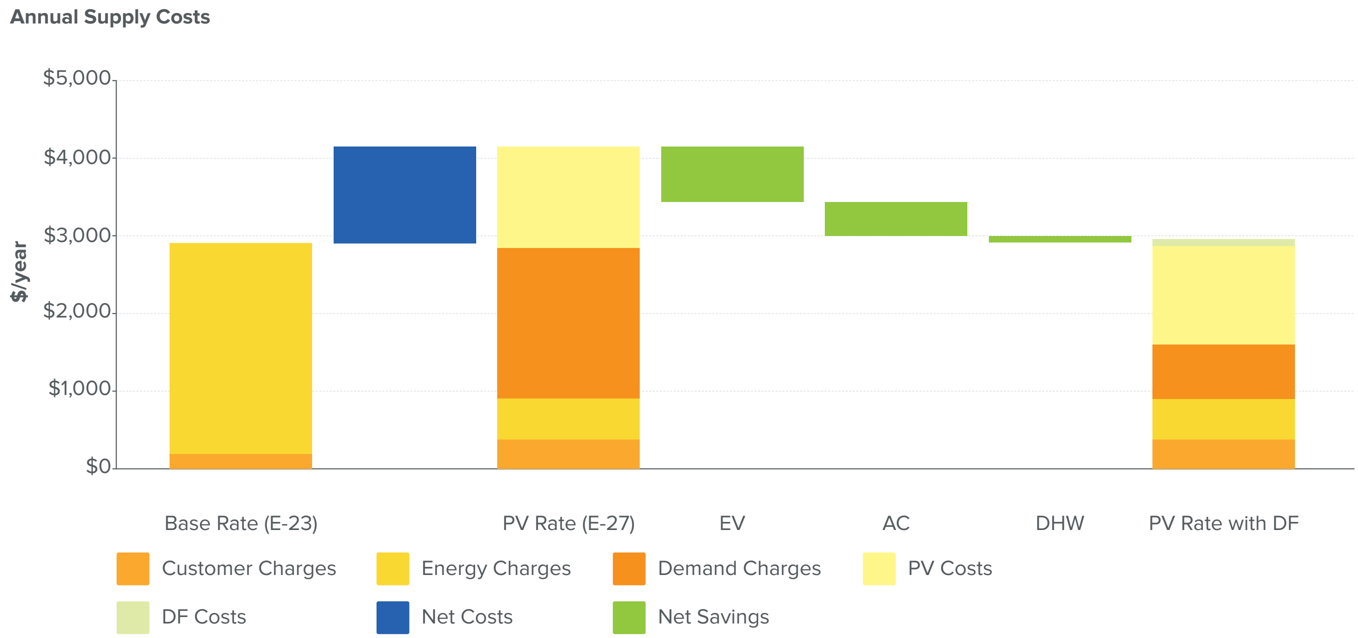


FIGURE 11
ANNUAL BILL REDUCTION POTENTIAL FOR SRP CUSTOMER



Market sizing

SRP's Customer Generation Price Plan was introduced in late 2014, so very few (fewer than 100) customers were enrolled in this rate as of June 2015.[63] However, demand flexibility's market potential in SRP could grow substantially to the extent that it supports the value proposition of behind-the-meter PV and allows customers to install PV, and switch to the new rate, without a cost penalty. Figure 9 shows that DF allows total customer costs, including PV financing costs at current prices, under E-27 to be on par with base-case full-service utility costs under the default rate, indicating a strong potential for a growing DF market.[v] In short, DF brings solar PV back to cost parity in SRP even after the new rate is implemented.

Across all potentially eligible customers that could install PV and switch to this rate in SRP territory, there is a total net bill savings potential of up to $240 million per year, with an associated investment opportunity of $110 million for vendors to provide customers with flexibility-enabling technology for EVs, AC, and DHW. These investments can unlock a rooftop PV market of up to 1.8 GW_{DC}, or $6.3 billion of total investment at today's prices, in SRP territory.

In addition to new solar PV customers, the potential exists for Arizona customers without PV to adopt a demand charge rate option; neighboring utility Arizona Public Service currently serves more than 100,000 residential customers on a demand charge rate. The large number of enrollments suggests that customers are willing to accept a demand charge when priced correctly, and indicates a potentially lucrative market for demand flexibility.

[v] Bill savings for a lower-consuming customer without an EV, moving from E-23 to E-27 with rooftop PV, may be larger than shown in our results, due to the large demand charge implications of on-peak EV charging; the demand charge savings available from DF from other levers (i.e., AC and DHW) for that customer would remain substantial (i.e., 35–45%).

SCENARIO 3: NON-EXPORTING ROOFTOP SOLAR PV RATE

Finding: Demand flexibility sustains rooftop solar economics when export compensation is zero

A proposal by the Hawaii Public Service Commission has asked the Hawaiian Electric Company (HECO) to offer a non-export option to new PV customers.[64] In a non-export scenario, rooftop PV owners receive no compensation or bill credit for PV energy they export to the grid (i.e., solar PV production has value to the homeowner only if used on-site). For analytic purposes, we maintain HECO's existing volumetric rate and assume that excess PV is not compensated by the utility; we analyze the economics of DF technologies for a full-service customer considering adding a rooftop PV system under the non-export rate.

We model a relatively large (10 kW_{AC}) PV system because in this case, the economics support large array sizes. This size is also suitable for the relatively high-usage customer (i.e., high AC use plus an electric vehicle) included in this analysis.

TABLE 9

SCENARIO-SPECIFIC MODELING SETUP: NON-EXPORTING ROOFTOP SOLAR PV RATE

VARIABLE	SCENARIO DETAIL
Utility	Hawaiian Electric Company (HECO)
Program name/Rate design	DG 2.0 Non-Export Proposal[65] (proposed option for new PV customers)
Geography (TMY3 location)	Honolulu, HI (Honolulu International Airport)
Customers participating	Approximately 270,000 utility customers; 51,000 NEM customers (as of 12/31/2014)
Fixed charges	$9.00/month
Demand charges	None
Energy charges	Inclining block from $0.34–$0.37/kWh; exports earn $0.00/kWh.
Customer PV array size analyzed	10 kW_{AC} (supplies ~80% of household demand)

SCENARIO FINDINGS SUMMARY (HECO)

- Cost-effective demand flexibility can **increase on-site consumption of rooftop PV from 53% to 89%.**
- Relative to the cost of solar PV without export compensation, participating customers can **save an additional $1,600/year (or 33% of total bills)** by taking advantage of DF, net of the cost of enabling technology.
- Demand flexibility can increase the value of non-exporting rooftop PV for new PV customers:
  - Across all potential non-exporting residential PV customers in HECO, there is a **net bill savings opportunity of up to $110 million per year.**
  - There is an **investment opportunity of up to $81 million** for vendors to help customers unlock these savings (i.e., purchases of flexibility-enabling technology for EVs, AC, DHW, dryers, and batteries—approximately $1,000/home).
  - This investment can support a **non-exporting rooftop PV market of up to 380 MW_{DC} ($1.3 billion of investment** at today's prices**)** in HECO territory, or 30% of the utility's peak load.

DETAILED FINDINGS

On-site consumption impacts

The combined control strategies can nearly double on-site consumption of rooftop PV compared to the uncontrolled case. In the base case, only 53% of production is consumed on-site; with all cost-effective DF levers among those studied (including dedicated battery storage), nearly 90% of PV generation is consumed on-site.

Cost-effective flexibility bundle

AC setpoint changes and optimal EV charging (even though an EV is only assumed to be plugged in at home and capable of daytime charging on weekends) are the least-expensive levers to increase on-site consumption, followed by thermal storage in electric water heaters. Electric dryers and batteries are both significantly more expensive flexibility levers than the other three loads, but are still cost-effective in this scenario given HECO's very high electricity rates. Additional battery capacity could likely enable near-100% cost-effective on-site consumption.

Customer bill savings

A customer considering solar PV in HECO territory, assuming the current rate structures even with no export compensation, still sees favorable economics for solar investment, due to HECO's high volumetric rates. The combination of PV with DF technology nearly halves net service costs, saving the modeled customer over $4,000 per year. The combination of demand flexibility and a large PV system offers substantially more savings potential to non-exporting customers than smaller PV systems with higher base-case self-consumption levels. For example, a 4 kW_{AC} system without demand flexibility would save the modeled customer only $1,400 per year.

FIGURE 12

ON-SITE CONSUMPTION OF ROOFTOP PV

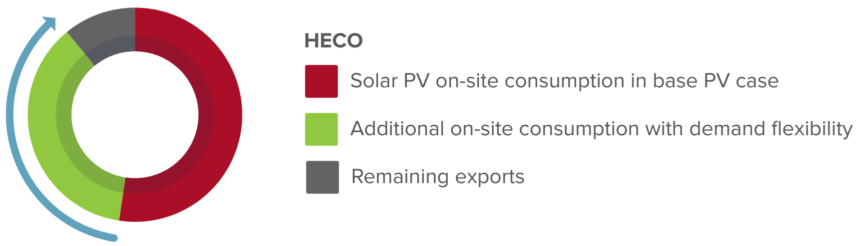


FIGURE 13

SUPPLY CURVE OF DEMAND FLEXIBILITY

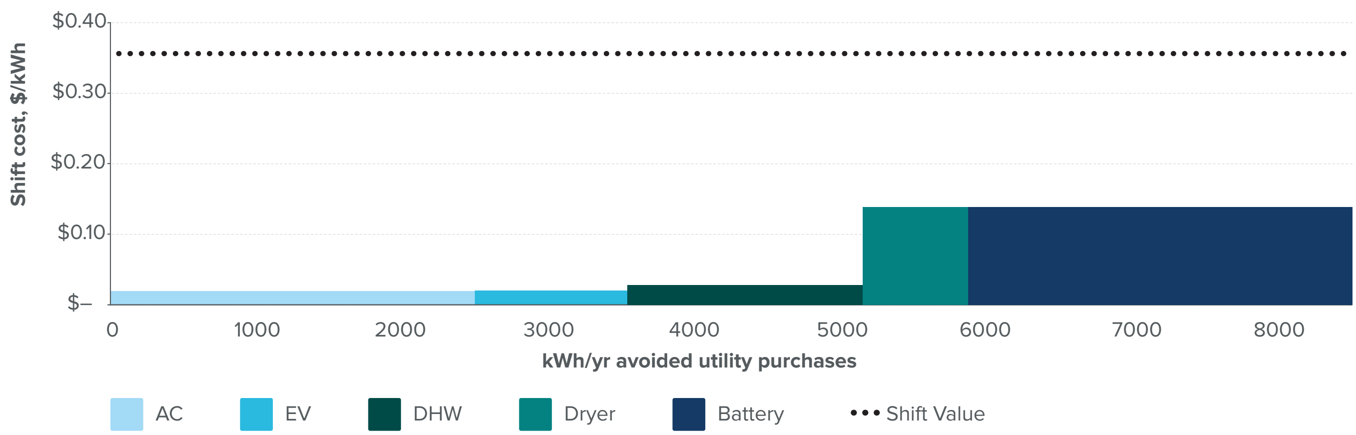
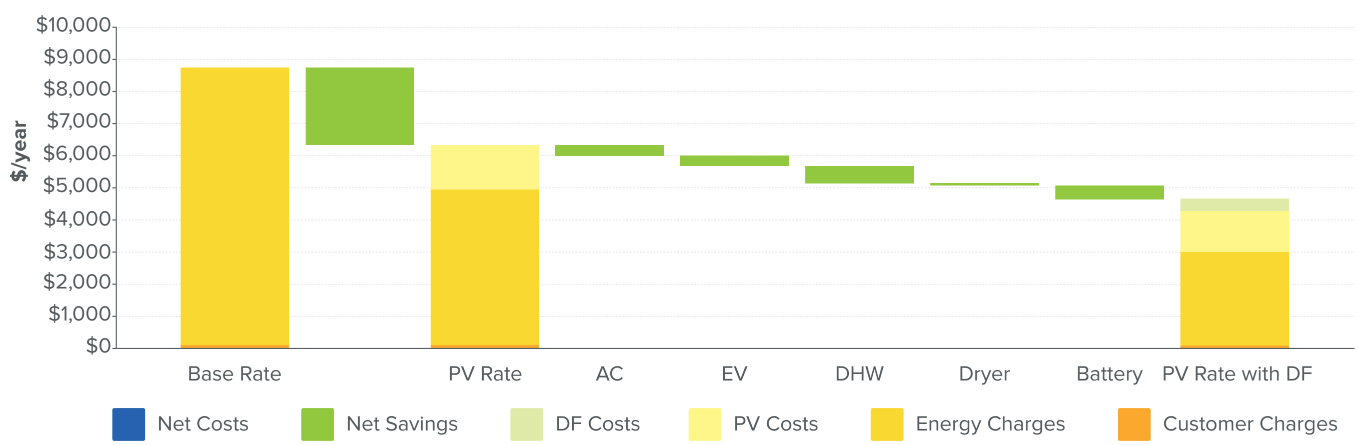


FIGURE 14

ANNUAL SUPPLY COST SCENARIOS FOR HECO CUSTOMER



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Market sizing

Depending on the final regulator-approved structure of HECO's non-export rate option, which is likely to incentivize non-exporting PV systems, demand flexibility could significantly improve PV economics and support even broader adoption of PV in Hawaii. Although HECO already serves nearly 50,000 net-metered customers and will continue to offer a rate option that compensates customers for exported solar in addition to its non-export option, DF may continue to expand the achievable market for new customers, depending on final changes to NEM terms. Additionally, HECO notes that non-export systems will not be subject to an interconnection review study,[66] substantially reducing the time from a signed customer contract to an operating PV system.

We find annual net customer bill savings from demand flexibility of up to $110 million per year if all eligible customers in HECO territory install PV under the proposed non-export rate. There is an investment opportunity of up to $81 million to enable these savings, supporting a non-exporting rooftop PV market of up to 380 MW_{DC}, or $1.3 billion of total investment at today's prices.

BOX 4

DEMAND FLEXIBILITY HELPS ADDRESS THE PROBLEMS HIGHLIGHTED IN THE "DUCK CURVE"

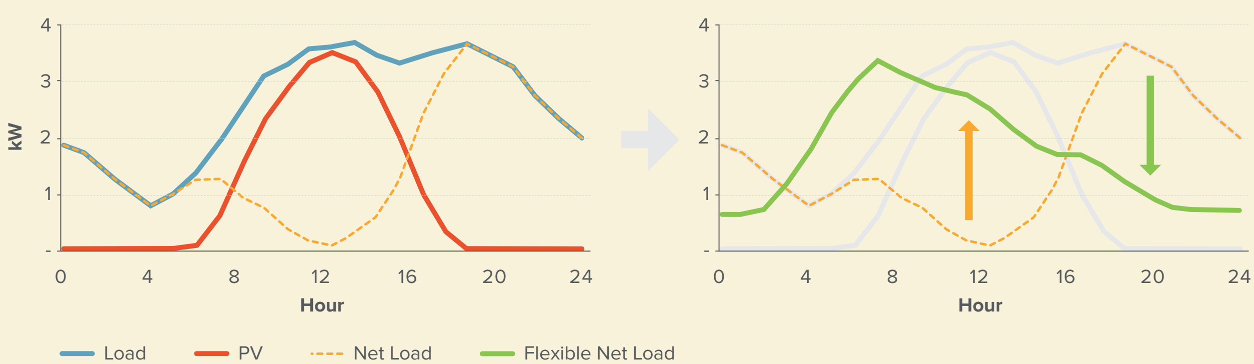
Utilities and regulators in areas with growing penetration of rooftop PV are beginning to address the "duck curve:" the scenario in which, after system demand is depressed during midday peak solar generation, a rapid ramp-up in generation is required to serve late-afternoon loads as solar PV generation decreases while loads remain high.[67]

Demand flexibility can play a significant role in mitigating the duck curve. The pairing of rooftop PV and flexible demand with more-granular price signals enables customers to shift consumption away from peak periods and reduce the steep ramping requirement. Among other strategies, this could include pre-heating water, pre-cooling houses, and timing electric vehicle charging to occur during solar PV generation or overnight. Our case analyses for HECO and Alabama Power illustrate the potential for customer loads to shift seamlessly into times of robust solar production.

In this illustration built from our HECO case analysis, a residential customer shifts consumption to the middle of the day, when PV generation peaks, to avoid sharply increasing demand when PV generation declines even as demand remains high. In doing so, both the ramping requirements and the risk of overgeneration (when demand falls below the output of generators that cannot be easily or cost-effectively ramped up and down) are reduced.

FIGURE 15

DEMAND FLEXIBILITY AND THE DUCK CURVE



SCENARIO 4: AVOIDED COST COMPENSATION FOR EXPORTED PV

Finding: Demand flexibility accelerates PV cost parity

Because of avoided cost compensation and mandatory fixed charges, solar PV has poor economics in Alabama Power territory. The utility offers avoided-cost compensation for all exported PV, rather than crediting at the retail rate, and also imposes a non-bypassable capacity charge of $5/kW-month for behind-the-meter generation. We analyze the economics of demand flexibility both for a customer with an existing PV system, and for a full-service customer considering adding a small rooftop PV system.

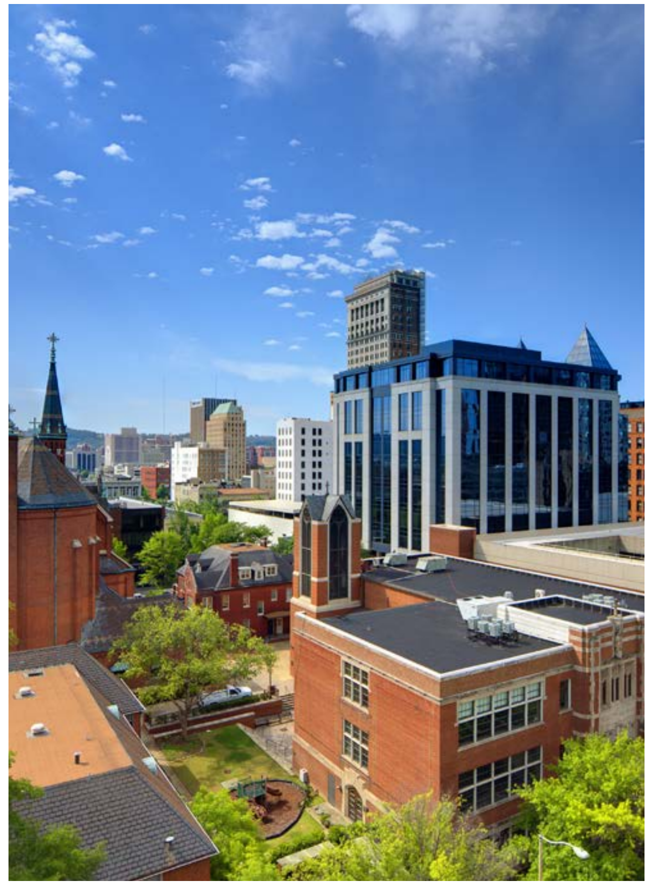


TABLE 10

SCENARIO-SPECIFIC MODELING SETUP: AVOIDED COST EXPORT COMPENSATION

VARIABLE	SCENARIO DETAIL
Utility	Alabama Power
Program name/Rate design	Alabama Power Family Dwelling Residential Service[68] and Purchase of Alternative Energy (PAE)[69] (mandatory for all PV customers; we modeled PAE Option A for export compensation)
Geography (TMY3 location)	Birmingham, AL (Birmingham Municipal Airport)
Customers participating	Less than 100 customers currently;[70] approximately 1.2 million total utility residential customers
Fixed charges	$14.50/month for all residential customers; additional $0.82/month and $5/month per kW of PV capacity for PV customers on rate PAE
Demand charges	None
Energy charges	$0.111/kWh (first 1,000 kWh); exports earn $0.0316/kWh (June–Sept), $0.0288/kWh (October–May)
Customer PV array size analyzed	4 kW_{AC} (35% of household demand)

SCENARIO FINDINGS SUMMARY (APC)

- Cost-effective demand flexibility can **increase on-site consumption of rooftop PV from 64% to 93%.**
- Relative to the cost of solar PV without export compensation, participating customers can **save an additional $210/year (or 11% of total bills)** by taking advantage of DF, net of the cost of enabling technology.
- Demand flexibility can **accelerate grid parity of rooftop PV by 3–6 years**, to 2020 under current rate structures, opening up the market for PV in Alabama. For example, in 2020:
  - Across all potential residential PV customers in Alabama Power territory, there is a **net bill savings opportunity of up to $210 million per year.**
  - There is an **investment opportunity of up to $230 million** for vendors to help customers unlock these savings (i.e., purchases of flexibility-enabling technology for EVs, AC, and DHW—approximately $400/home).
  - This investment can support **a rooftop PV market of up to 2.9 GW_{DC} ($10 billion of investment** at today's prices**)**—24% of the utility's peak demand.

DETAILED FINDINGS

On-site consumption potential

Only small PV systems approach cost-effectiveness under the rate structure analyzed because of the PV-specific capacity charge. Demand flexibility can increase on-site consumption from small systems from 64% with uncontrolled loads to over 93% with flexible loads—in other words, it virtually eliminates export and turns PV into a behind-the-meter resource.

Cost-effective flexibility bundle

Demand flexibility from AC and DHW levers are most cost-effective.[vi] EV charging is also cost-effective but represents a smaller load-shifting potential given the small PV array size. DF-capable dryers and batteries are not cost-effective, largely due to the small PV array size and the resulting limited potential for load-shifting after applying other flexibility levers.

Customer bill savings

Due to low retail rates and a relatively low capacity factor (18%[vii]) for PV in Alabama, rooftop PV is barely cost-competitive at our assumed installation prices, even under rate structures that would be favorable to PV, such as NEM or the absence of solar-specific fixed charges. With Alabama Power's avoided cost export compensation and high solar-specific fees, PV would add significantly to total service costs for a typical customer. However, for a customer with an existing PV system, DF technologies can reduce net utility bills by 11%. For a customer considering adding a new PV system, adding DF reduces the cost penalty of doing so to less than $35/month higher than full-service utility costs. A large fraction of that remaining cost penalty ($20/month) is due to Alabama Power's specific and non-bypassable capacity charge for PV customers. If a completely non-exporting solar array were found to be exempt from the solar-specific capacity charge, this cost difference would be reduced to $15/month or less.

[vi] Alabama Power offers a $200 rebate for new electric water heaters, negating the incremental cost of adding demand flexibility controls to this appliance.

[vii] See Appendix B for NREL SAM results.

FIGURE 16

ON-SITE CONSUMPTION OF ROOFTOP PV

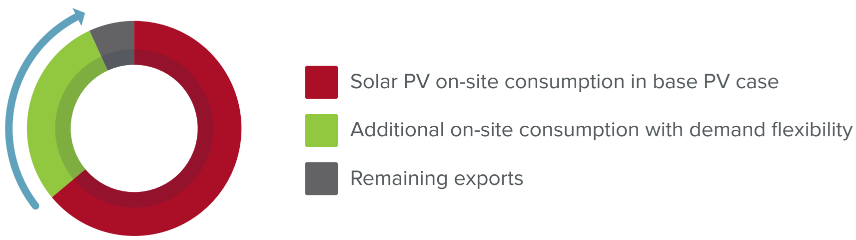


FIGURE 17

SUPPLY CURVE OF DEMAND FLEXIBILITY

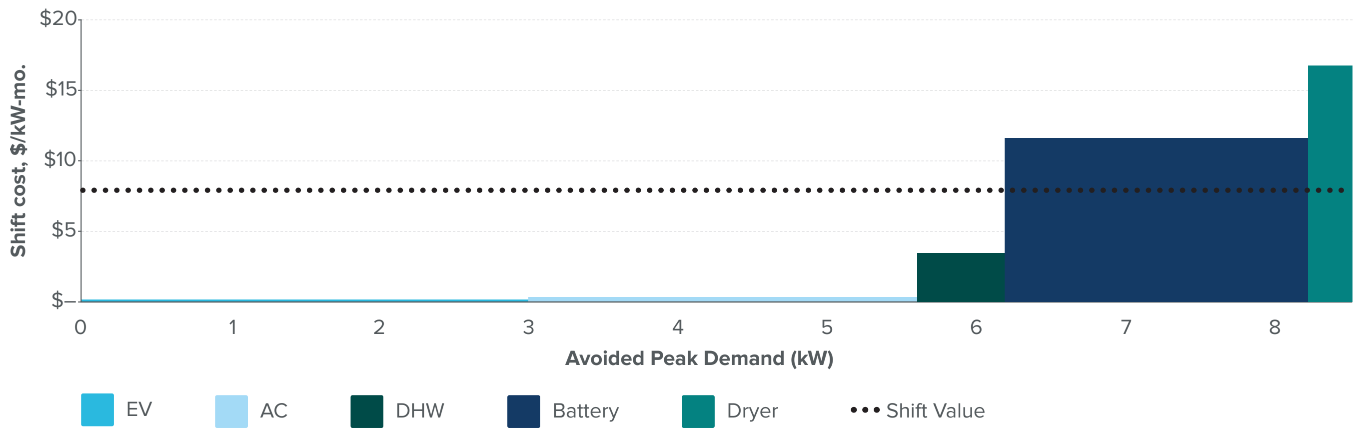
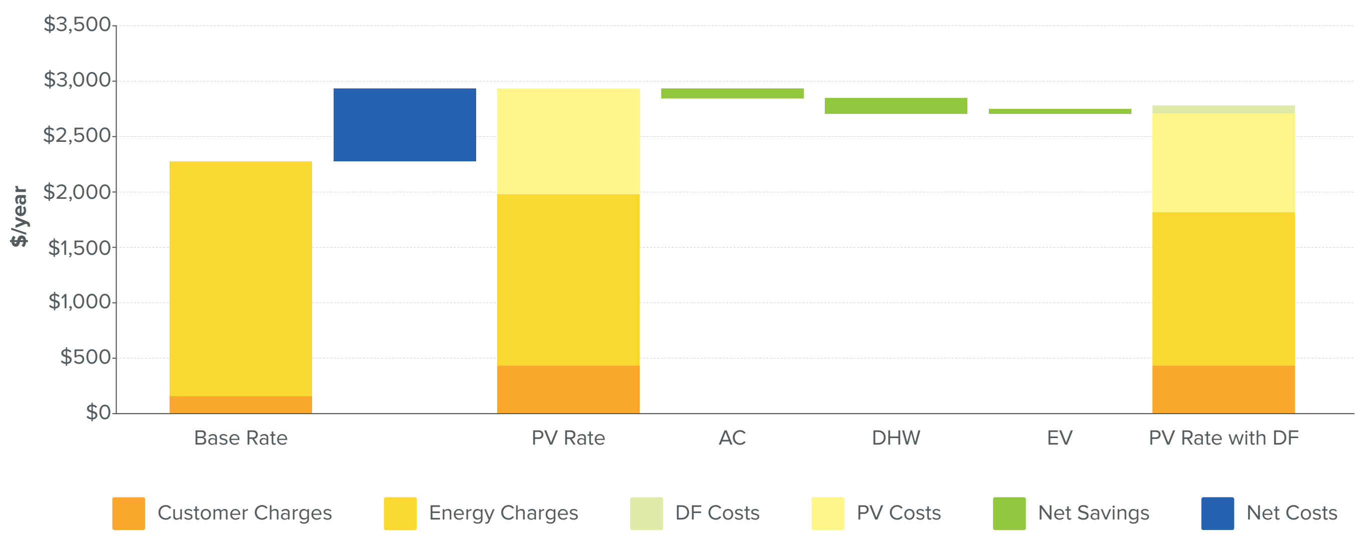


FIGURE 18

ANNUAL SUPPLY COST SCENARIOS FOR ALABAMA POWER CUSTOMERS



Market sizing

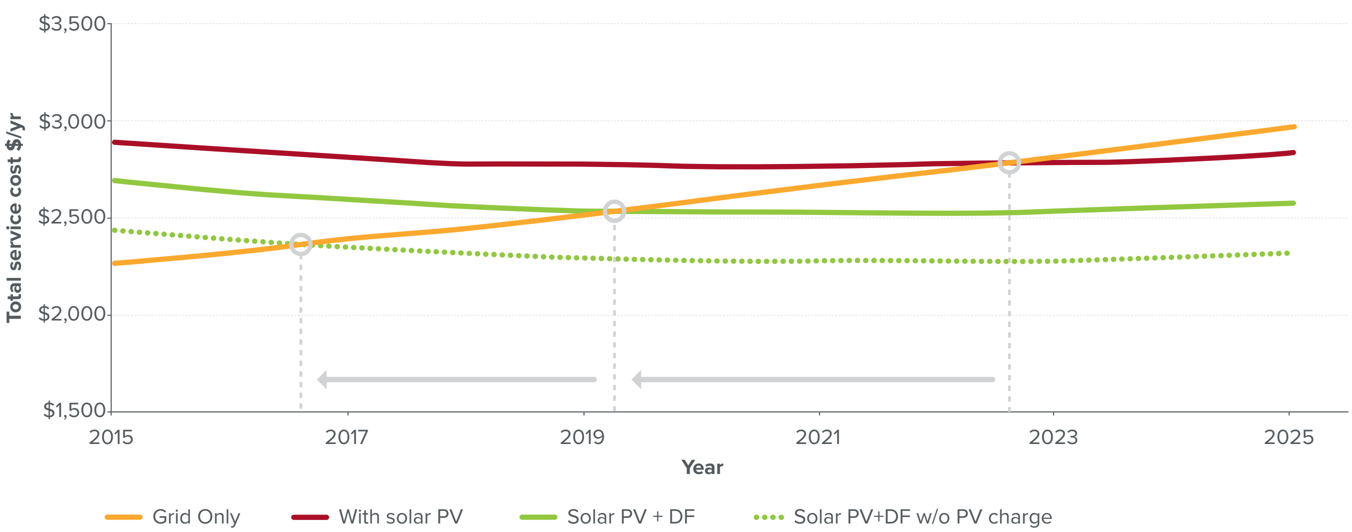
As PV installation costs continue to decline, and utility pricing in Alabama grows at historical rates, demand flexibility can play a large role in growing the PV market in the state. Assuming a 10% annual cost reduction in PV installation prices and a 3% real annual increase in utility rates,[viii] rooftop PV alone under Alabama Power's rates will not be cost-competitive until approximately 2023. Adding DF accelerates parity to 2020; if the PV-specific charge can be avoided by installing an entirely behind-the-meter, self-consuming system, grid parity is accelerated to 2017.

We show the trends in total system costs—the sum of utility bills, PV system, and DF costs—for these scenarios in the figure below. Total costs fall in the PV scenarios due to assumed falling installation prices through time, and costs rise in later years for all scenarios due to the assumption of rising utility rates, but demand flexibility can be used to dampen this latter effect and improve the value proposition of PV. This capability may help unlock the PV market for Alabama Power's 1.2 million residential customers.

Our analysis indicates that PV plus demand flexibility will reach grid parity in Alabama Power territory by 2020. If all eligible customers leverage the ability of flexiwatts to cost-effectively install PV at this point, this would represent a total net bill-reduction opportunity of up to $210 million per year from demand flexibility. An investment opportunity of up to $230 million to provide customers with flexibility-enabling technology would unlock these savings, as well as open up a 2.9 GW_{DC} ($10 billion of total investment at today's prices) market for residential rooftop PV.

FIGURE 19

TRENDS IN DIFFERENT SUPPLY COST SCENARIOS FOR ALABAMA POWER CUSTOMER



[viii] According to EIA Form 861 data, from 2005 to 2013 (the latest year data are available), Alabama Power average residential rates grew at 2.2% per year in Consumer Price Index-adjusted real dollars, and the utility proposed a new 5% rate increase effective January 2015.

BOX 5

UTILITIES USE DEMAND FLEXIBILITY TO DELIVER CUSTOMER VALUE BEYOND COST SAVINGS

NB Power – PowerShift Atlantic

Grid-interactive water heater deployment provides customer and grid benefits

The PowerShift Atlantic project seeks to enable grid operator control of loads like water heaters in order to help integrate wind into the electric grid in New Brunswick, Nova Scotia, and Prince Edward Island.[71] Project partner utilities, including NB Power, control thousands of water heaters to respond to fluctuations in wind output. Customers signed up to participate in this program in order to contribute to the research agenda of the program, whose goal was to lower the costs of renewable energy integration over the long run. Utilities recognize that further customer adoption can be spurred using adaptations to existing water heater rental business models.[72] Utilities or their partners could install grid-interactive water heaters that can deliver grid value, while simplifying and improving the customer experience by installing, insuring, and maintaining the appliance for a fixed monthly fee.[73]

Steele-Waseca Cooperative Electric – Community Solar PV + Water Heaters[83]

Product bundles provide value on both sides of the meter

Steele-Waseca Cooperative Electric (SWCE) in Minnesota offers a community solar program in which customers can purchase shares of energy generated by an off-site PV array. SWCE also offers a grid-interactive water heater program in which the utility gives free, large-capacity water heaters to participating customers that ensure that water heating loads occur during off-peak times. In order to improve customer value, and drive participation in both programs in order to maximize grid benefits, the utility has bundled the community solar PV and water heater programs into the Sunna Project, in which customers are offered a steeply discounted price for a community solar PV share in exchange for participation in the water heater program. By offering this bundled package, the utility drives adoption of a valuable grid resource while offering customers increased access to renewable energy.

San Diego Gas & Electric – Vehicle-Grid Integration (VGI)[75]

EV charging pilot can increase access for customers and smooth EVs' grid impacts

San Diego Gas & Electric (SDG&E) has introduced a Vehicle-Grid Integration (VGI) pilot program that will install EV charging infrastructure in workplace and multi-family housing environments to increase access to charging services while examining the impact of time-variant pricing on charging behavior. SDG&E has piloted a smartphone app that requests customer preferences for the maximum hourly price the driver is willing to pay, the planned departure time of the vehicle, and the total kilowatt-hours needed to charge the vehicle.[76] The SDG&E system then optimizes vehicle charging to provide the lowest cost charge to customers while minimizing the impact of vehicle charging to the grid. The utility gains some control of large loads, and customers get access to charging infrastructure and control over timing and costs of vehicle charging.

BOX 6

ALTERNATIVE SCENARIO: *THE ECONOMICS OF LOAD DEFECTION,* REVISITED

Finding: Utilities should see demand flexibility as a huge opportunity to reduce grid costs, but under unfavorable rate structures, demand flexibility can instead hasten load defection by accelerating solar PV's economics in the absence of net energy metering (NEM).

Our April 2015 report *The Economics of Load Defection* examined the economics of grid-connected solar-plus-battery storage systems, and found that due to rapidly declining costs, these systems are likely to become cost-competitive with utility rates in the near future.[77] By examining the range of utility rates in the Northeast region of the United States, we found that solar-plus-battery systems could serve 50% of total regional residential load at an average of 15% below utility prices in 2030, leading to massive "load defection" from utilities and dramatically reducing utility revenues.

These results hinge upon an emerging theme in utility rate design conversations: how to compensate customers for behind-the-meter generation (e.g., solar PV) that is exported to the grid. Current net energy metering (NEM) tariffs are the norm, but several utilities (including Alabama Power) and trade organizations have proposed compensating exported PV at the avoided cost of energy.[78] This simple metric risks undervaluing the true benefits of distributed PV.[79] So how would customers respond, and what would be the implications of a large-scale move to this compensation mechanism? What if more utilities adopt rate structures to discourage solar PV deployment? Can the rooftop PV market continue to grow? Are customers gaining competitive tools to defeat utilities' efforts to discourage competition from PV systems?

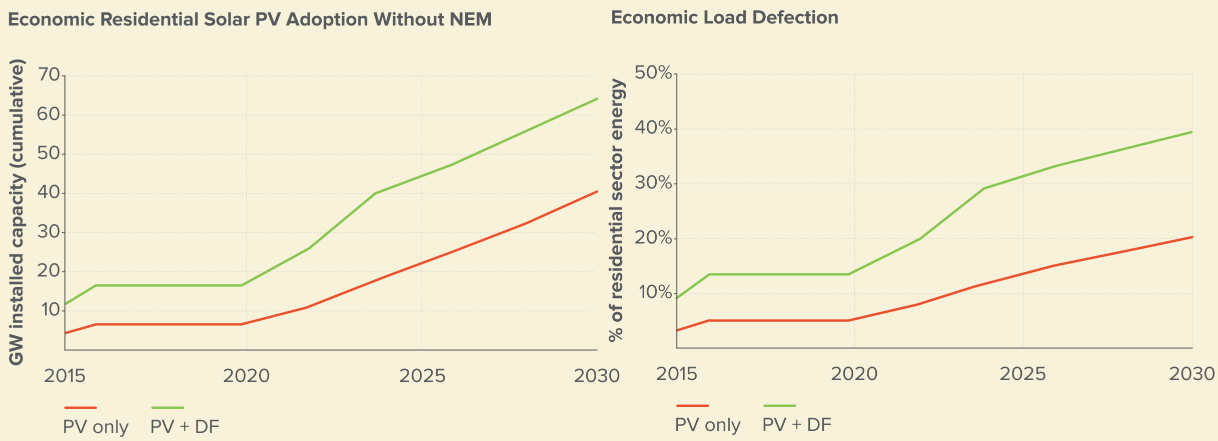
In the load defection analysis, we calculated the potential of batteries to raise on-site consumption of PV energy in the absence of export compensation (e.g. net energy metering). Here we update that analysis by looking at DF as a potential lower-cost alternative to dedicated battery storage to improve the value proposition of rooftop PV if export compensation were reduced or eliminated. We examine the same range of rates in the U.S. Northeast, and use the same PV cost decline and utility rate increase assumptions as in the load defection analysis. We assume that export compensation reflects avoided wholesale energy costs, and calculate optimal PV system sizes both with and without demand flexibility. Under this assumption of a move towards avoided-cost export compensation, we find that DF increases the total PV market in the Northeast by 60% through 2030, accelerating solar PV economics—and counteracting the effects of utility rates that limit export compensation.

Demand flexibility helps customers consume more PV output on-site, leading to larger cost-effective PV arrays as well as more customer demand met by rooftop PV rather than by utility sales. The combination of these two factors greatly accelerates the load defection potential of rooftop PV. Adding demand flexibility to PV systems in the Northeast raises the cost-effective load defection potential from 20% of residential load in 2030 with PV alone to nearly 40% with DF.

(box continues)

FIGURE 20

NORTHEAST U.S. SOLAR PV MARKET POTENTIAL WITH AND WITHOUT DEMAND FLEXIBILITY



Demand flexibility should be seen as a golden opportunity, not an existential threat.

As we discussed in *The Economics of Load Defection*, the U.S. electricity system is at a fork in the road. A utility implementing a rate structure like the one examined in this analysis may alienate customers and encourage load defection by failing to value appropriately the contributions of rooftop PV and the system-level capabilities of demand flexibility. Utilities should instead choose the mutually beneficial path of offering rates that fairly compensate customers for both solar PV and the use of flexiwatts, in order to align incentives for customers so as to reduce system costs rather than decimate utility revenues.

IMPLICATIONS AND CONCLUSIONS

04

IMPLICATIONS AND CONCLUSIONS

DEMAND FLEXIBILITY'S POTENTIAL VALUE MAY BE MUCH LARGER THAN WE ESTIMATE

We have presented the value of demand flexibility in four specific utility cases, both under granular rates that can lead to a more-integrated grid and under assumptions of rates that encourage self-consumption. However, we believe that the total value may greatly exceed the potential estimates presented here for several reasons.

1. **We analyze only five levers in the residential sector, but other end-uses, including commercial and industrial loads, can also be made flexible.** We do not analyze all residential loads that could be made flexible with evolutions in business models and technology. Moreover, commercial and industrial customers are already largely served by more-granular rates (i.e., time-varying energy pricing and demand charges) that incentivize DF, and solutions are rapidly emerging to capture the savings potential in these buildings (see Box 7).
2. **We assume the incremental cost today of flexibility-enabling technology, but that cost could be much lower if integrated into appliances at the factory.** For all of the appliance loads we model in this paper, we accounted for the incremental cost to enable communications and control to enable DF. However, these costs could be much lower if DF capabilities were integrated into these appliances at the factory, and not added as a retrofit.
3. **There are many more granular rates available to customers than those we analyze in this paper.** Approximately 3% of U.S. residential customers—4 million households—already participate in time-varying pricing, and approximately 65 million more have opt-in programs available to them.[ix] Even given that the majority of these programs are simple time-of-use rates, the DF strategies that we present in this report can be tailored to deliver savings to broad swaths of customers under different rate structures around the country.
4. **Demand flexibility technology is already being adopted by a growing number of customers, providing a large existing customer base.** Many residential customer segments have already adopted the enabling technology of DF, particularly network-enabled smart thermostats and electric vehicles. To the extent that companies (for example, thermostat manufacturers) can identify and recruit customers to use flexiwatts to reduce bills under existing or new granular rate structures, these customers represent a ready pool of potential savings in utility territories around the country.

While the markets we analyze in this report may be relatively small—hundreds of millions of dollars per year across our four scenarios—compared to the total U.S. market, they represent possible aspects of the near-term future of the grid, for better or for worse. As regulators encourage and utilities pursue well-designed rates to better reflect cost causation and enable massive reductions in grid capacity investments, demand flexibility unlocks a large market for cost reductions. To the extent that rates evolve unfavorably, incentivizing on-site consumption and thus threatening continued PV deployment, DF offers insurance for the rooftop PV market and enhances the value proposition of rooftop PV for customers.

[ix] EIA Form 861, 2013 (calculated by summing the number of residential customers served by utilities that have customers enrolled in opt-in time-varying rates).

BOX 7

COMMERCIAL AND INDUSTRIAL SECTOR DEMAND FLEXIBILITY

Many commercial building and industrial facility solutions for demand flexibility already exist. Commercial buildings in most utility territories face demand charges, which can account for a substantial portion of a building's monthly bill, and can be addressed directly by flexiwatts and/or storage technologies. Below, we outline four distinct strategies, commercially available today, to manage demand charges, optimize for time-varying energy prices, and improve control and visibility of large loads in commercial buildings.

COOLING ENERGY FLEXIBILITY[x]

Use case: Large commercial buildings with central space cooling facilities (e.g., office towers)

Loads under control: Central chiller plants and other space-cooling equipment

Approach: Software that couples calibrated industry-standard building energy models with advanced optimization methods (e.g., model predictive control) can leverage the thermal mass of large buildings to optimize energy consumption throughout the day. This can reduce both total energy used as well as peak afternoon demand by optimizing zone setpoint schedules against utility rate components (e.g., time-varying energy charges, monthly peak demand charges).

Cost structure: The approach requires no investment in different cooling equipment to achieve savings. Software setup costs for initializing modeling and optimization frameworks, on the order of $30,000 per controlled building, are fixed. Ongoing support, tuning, and maintenance are small, and marginal costs per building at scale are minimal.

Savings potential: Depending on specific utility rate structures, both peak demand and on-peak energy use can be reduced by up to 30% with minimal changes in occupant comfort. Importantly, this strategy can also reduce total energy use, including off-peak energy, by optimizing cooling schedules against equipment performance curves and ambient temperatures.

QUEUED POWER ACCESS[xi]

Use case: Buildings with multiple motors and/or cycling loads (e.g., retail and telecom small data centers)

Loads under control: Individual loads behind the meter (e.g., HVAC, refrigeration, electric motors, pumps, battery charging, etc.)

Approach: This solution relies on enforcing a non-disruptive queue for power demands—an approach similar to one used in the IT and telecommunications industries to manage network bandwidth. The service queues the operation of individual loads, shifting a small percentage (e.g., 4%) of energy use in order to reduce peak demand. In practical applications for HVAC loads, this approach schedules a compressor's startup time within 300-second time slots, causing no perceivable impact on end-use quality of service.

Cost structure: If there are no building automation systems (BAS) in place, the communications hardware required can range from $2,000–3,000 per facility. If an open standards BAS is in place, software integration, commissioning and setup costs range from $20,000 to $75,000 depending on BAS scale and facility complexity. Ongoing software service fees are as low as $0.005/kWh.

(box continues)

[x] See, for example, QCoefficient

[xi] Queued Power Access is a trademark of eCurv, Inc.

(continued)

Savings potential: Queuing access to a shared power supply can achieve peak demand reductions of up to 40%, up to 13% total energy savings, and additional benefits including built-in load monitoring to identify equipment performance issues. Depending on specific utility rate structures, total annual energy bill savings range from 11% to 27% per building.

SMART LIGHTING CONTROLS[xii]

Use case: Commercial and industrial facilities with large and/or complex lighting control systems (e.g., office buildings, warehouses)

Loads under control: Individual lighting fixtures

Approach: Installation of networked controls for lighting systems allows fine-tuning of lighting fixture output according to occupant presence and preference, real-time daylighting availability, and code-specified minimum output levels. Dimmable fixtures and advanced controls can also contribute substantially to energy and peak demand savings for buildings with high lighting requirements.

Cost structure: Control hardware cost requirements are on the order of $1,000–$3,000 per facility. Costs for efficient lighting hardware (e.g., dimmable LED fixtures) are additional and scale with facility size, but offer rapid payback in energy savings.

Savings potential: Peak demand reductions on the order of 10–20% are achievable depending on building type, load profile, and usage pattern. There are also substantial reductions in total lighting energy usage as well as improvements in lighting quality and flexibility to meet occupant preferences.

BATTERY STORAGE

Use case: Any commercial building

Loads under control: Dedicated battery energy storage hardware

Approach: Predictive analytics software coupled with power electronics can optimize the charging and discharging profile of dedicated, behind-the-meter battery systems in order to minimize peak demand levels for large facilities. Peak demand of any type of load can be minimized by battery systems of the appropriate size.

Cost structure: Hardware cost requirements are currently on the order of $350/kWh or less for commercial building battery systems.

Savings potential: Each kW of battery storage capacity has the potential to reduce 1 kW of peak demand and eliminate the associated monthly peak demand charges. Battery systems can also shift on-peak energy to cheaper off-peak hours for buildings with time-varying energy rates; however, there are energy losses on the order of 15–20% due to inverter inefficiency.

[xii] See, for example, EdgePower

RATE DESIGN CAN UNLOCK FAR MORE OF DEMAND FLEXIBILITY'S POTENTIAL VALUE

Our analysis suggests that the fundamental economics of demand flexibility are favorable, but many barriers remain to be overcome by regulators, utilities, and third-party innovators in order to capture this value. Of particular importance, to promote the adoption of demand flexibility and line up incentives for customers to help reduce system costs, the design of rates should include four key features:[80]

1. *Increased granularity:* to the extent possible, residential rate design should unbundle components of usage (e.g., energy, capacity, ancillary services) and add temporal (e.g., peak / off-peak energy and capacity) and locational components.

2. *Technology agnostic:* rates should not prefer or discriminate against specific technologies and instead be designed to charge and compensate customers at prices that reflect marginal costs for services consumed and provided.

3. *Expand customer choice:* customers should not be constrained to one rate option designed to reflect the cost causation of an "average" customer. Customers should be able to opt in to rate structures of varying granularity according to their preferences and the availability of technology to enable cost reductions.

4. *New default options:* utilities typically have multiple rate options for residential customers, and almost universally, the default option is the volumetric energy charge with no temporal variation or attribute unbundling. New default options can help unlock the value of demand flexibility for many more customers than are currently enrolled in opt-in granular rate structures.[81]

STAKEHOLDER IMPLICATIONS

Innovation within the U.S. electricity system today is in a holding pattern, as emerging technologies and capabilities confront a system built on twentieth- or even nineteenth-century paradigms. Every stakeholder needs to act on the incentives that exist today. To capture the benefits of demand flexibility for customers and the system at large, three key stakeholder groups need to work together to arrive at a higher-quality, lower-cost outcome: third-party innovators, utilities, and state regulators. Only through coordinated action can we shift from the current state—which works well but at a higher than necessary cost—to one that uses all available levers to run the system more efficiently.

Third-party innovators already have the technology and business models to capture the value of flexiwatts (and the scenarios covered in this paper highlight real opportunities to do so today) but are limited in scale by a lack of granular rates or local market participation options available from many utilities. Utilities in many cases need regulatory support and incentives to introduce rates that would enable DF to reduce system costs. State regulators can encourage rates that scale demand flexibility, but need to see demonstrated capacity from innovators to ensure that customers can respond in ways that successfully reduce system costs. In this way, unilateral action by any of the stakeholders is challenging.

Scaling demand flexibility and moving the grid to a lower-cost solution requires concerted and coordinated action around a common goal: to fully harness the value of flexible demand to address grid and customer challenges. We lay out key actions below for each stakeholder group, but the ability to capture the value of flexiwatts at scale will ultimately rely on the success of integrated efforts to find win-win-win value propositions for customers, utilities, and third-party service providers alike.

THIRD-PARTY INNOVATORS: PURSUE OPPORTUNITIES NOW TO HONE CUSTOMER VALUE PROPOSITION

Many different kinds of companies can capture the value of flexiwatts, including home energy management system providers, solar PV developers, demand response companies, and appliance manufacturers, among others. These innovators can take the following actions to capitalize on the DF opportunity:

Take advantage of opportunities that exist today

Low-cost, high-capability technology to achieve demand flexibility is available today; scaling the market requires merging this technology with business models that seamlessly deliver customer value. Forty million customers today have access to opt-in granular rates; innovators can empower these customers to save money on their bills by providing products and services that complement or compete with traditional, bundled utility energy sales. The scenarios discussed in this paper illustrate the range of present-day opportunities for developers to do so; these scenarios represent an opportunity to refine the customer value proposition and test a variety of solutions that can allow these business models to scale in the future.

Offer customers more than just bill savings

Granular rates and demand flexibility can offer direct bill savings, but other drivers of customer demand have been proven to be potentially more important. Similar to efficiency—where many retrofits are driven by improved comfort or resale value, with bill savings as a secondary value—DF's ability to improve the customer experience might be a bigger draw than savings alone.

Companies can use DF to enhance proven strategies for different customer segments:

- The potential to offer DF bundles that deliver bill savings along with desirable consumer products (e.g., smart thermostats, rooftop PV, electric vehicles) may offer a ready customer base and cross-marketing opportunities for third-party providers. To broaden the market even further, look for opportunities to find low-cost, streamlined solutions for lower-income, lower-usage customer groups.
- Offer better, not just cheaper, services with demand flexibility-enabled products by streamlining maintenance and upkeep of appliances (e.g., water heating,[82] air conditioning).[83]
- Several companies have built successful load management programs for certain customer segments using targeted behavioral messaging (e.g., utility bill inserts that include comparisons to average neighborhood bills);[84] adding DF technology may offer the opportunity to enhance these programs.
- Many customers make investment decisions for appliances based on first cost alone. Companies can pursue strategies to make DF-enabled appliances the least cost option a potential buyer sees when making purchase decisions. An example is offering rebates on appliances whose costs can be covered by a shared savings model with the customer over the life of the appliance.
- Just as major home appliances already have Energy Star ratings and stickers indicating the annual cost to operate, DF-capable appliances can similarly carry a flexibility rating. These ratings could indicate the added annual value that demand flexibility offers customers who choose to tap into it, and would send a potentially powerful signal to consumers about the explicit monetary value of demand flexibility.

Pursue standardized and secure technology, integrated at the factory

Standardization and interoperability are vital for DF solutions to achieve scale and deliver grid and customer value.[85] Many solutions exist to allow low-cost integration of communications and control technology at the time of manufacture;[86] by incorporating standardized technology by default for consumer appliances, and not as a retrofit, upfront costs for flexibility can fall precipitously and widen the available market. Developers should also consider customer privacy and security in developing software and communication protocols to support flexibility, in order to mitigate some stakeholders' concerns around adoption of networked, flexible loads; close, early, and universal attention to security is essential in order to avoid highly publicized mishaps that give demand flexibility a bad name.

Find partnerships to monetize demand flexibility in front of the meter

Once companies have achieved sufficient scale in a utility service territory with customer-facing models, they can seek out additional opportunities to integrate programs that deliver further grid value (e.g., reduced peak capacity needs, renewable integration, etc.), in partnership with host utilities or other service providers. Traditional demand response models have been slow to scale, but by finding innovative ways to get demand flexibility into customer homes, companies can combine customer value with grid value to grow revenue and reduce system costs.

UTILITIES: LEVERAGE WELL-DESIGNED RATES TO REDUCE GRID COSTS

Utilities of all types—vertically-integrated, wires-only, retail providers, etc.—can capture DF's grid value by taking the following steps:

Introduce and promote rates that reflect marginal costs

By offering enabling rate options that allow customers to respond to granular pricing according to their preferences and technological ability, utilities can help customers lower their bills while reducing grid costs. On the other hand, if rates offer no customer incentive to reduce grid costs (e.g., high fixed charges, uneconomic on-site consumption incentives, poorly designed demand charges), DF may instead empower and encourage customers to reduce their bills (i.e., reduce utility revenue) without creating a commensurate drop in utility costs. This could provide customers major benefits from PV and other DERs, while depriving utilities of the benefits of flexiwatts they could otherwise capture.

Consider flexiwatts as a resource, not a threat

While our analysis focuses on the customer economics of demand flexibility, as a resource deployed at scale it has massive potential to reshape load profiles to reduce peak loads, avoid high-price energy production, and integrate renewable energy. Having flexible demand as well as flexible supply is a fundamentally better and smarter way to run a network—flexiwatts can be as effective as generation capacity in meeting many grid needs. Utilities should consider demand flexibility a resource, not a threat, and figure out how to harness it. Treating flexiwatts, PV, and other DERs as threats through unfavorable rate design may be a self-fulfilling prophecy.

Harness the potential of enabling technology and third-party innovation

Utilities can maintain a simpler customer experience despite increasing rate complexity by coupling granular rates with seamless, automated technology and third-party, customer-facing business models. As discussed above, third-party innovators can provide products and services that deliver flexiwatts alongside other desirable customer outcomes; these solutions coupled with granular rates can help utilities ensure that new rates address system cost concerns.

REGULATORS: PROMOTE FLEXIWATTS AS A LEAST-COST SOLUTION TO GRID CHALLENGES

In order to ensure that demand flexibility reaches its full potential to reduce system costs, and that third-party innovation can empower customers to reduce their bills, state regulators have a role to play in encouraging utilities to promote and fully value flexiwatts as a low-cost resource. Regulators should consider the following:

Recognize the cost advantage of demand flexibility

Regulators should recognize the power of innovation to deliver DF at very low cost compared to traditional infrastructure investments. Some infrastructure investments are likely prudent to ensure system reliability, but investments in DF should be considered as a lower-cost alternative when and where appropriate. Third-party business models that harness DF can deliver many sources of value to customers; by letting the customer value proposition drive the adoption of flexibility, the net cost to the grid to offset traditional investment can be very low. To the extent that grid-level technology may be required to enable demand flexibility (e.g., advanced metering infrastructure (AMI)), regulators can help enable their wide adoption, while recognizing that there are many available options to achieve different communications and control goals (e.g., internet-connected home energy management systems, smart inverters, etc.) that may not require significant upfront investment.

Encourage utilities to offer a variety of rates to promote customer choice

Demand flexibility's ability to provide value to the grid and reduce system costs rests on a foundation of well-designed granular rates. Though there are many customers who have the option to participate in granular rates today, these rates still need to reach wider adoption (and likely some increase in granularity) in order to capture the grid cost savings of the magnitude discussed in our analysis. Regulators should balance the potential complexity of highly granular rates against the attractive value proposition for customers and the grid. A growing body of evidence suggests defaulting customers to more granular rates can provide both savings and a positive customer experience.[87] However, maintaining the availability of less granular, more traditional block, volumetric rates can help to ensure that customers without the ability or interest to adopt new technologies can maintain a simple customer experience.

Encourage utilities to innovate and seek partnerships to harness demand flexibility

In order to capture the cost advantage of flexiwatts, regulators should encourage utilities to embrace the potential of granular rates, seamless technology, and innovative, customer-facing business models that help customers respond to price signals that reflect system costs. Regulators should recognize that these customer-facing solutions might come from utilities themselves, but often third parties can offer customers a broader variety of innovative solutions. Regulators should encourage utilities to embrace this, and offer rates that allow customers to save money and reduce grid costs by adopting competitive third-party services.

APPENDIX A

ESTIMATING DEMAND FLEXIBILITY GRID VALUE

APPENDIX A
ESTIMATING DEMAND FLEXIBILITY GRID VALUE

In order to quantify the value of avoided generation and T&D capacity, we adapted a method employed by the Brattle Group to determine the potential market size for demand response in the article "The Power of 5%." [88]

TABLE OF ASSUMPTION VALUES

	ASSUMPTION/CALCULATION	VALUE	UNIT	SOURCE/CALCULATION
A	U.S. non-coincident peak	771,944	MW	NERC
B	Market potential of residential DF	7.9%	% of peak	see text
C	End-use peak demand reduction	60,984	MW	A * B
D	Reserve margin	15%	% of peak	common industry assumption
E	Line losses	8%	% of energy at peak	common industry assumption
F	System-level MW reduction	75,742	MW	C*(1+D)*(1+E)
G	Value of capacity	$91	$/kW-yr	EIA AEO 2013
H	T&D % of generation capacity cost	30%		see text
I	Annual avoided capacity cost (generation)	$6,897	MM $/year	G*F
J	Annual avoided capacity cost (T&D)	$2,069	MM $/year	H * I

We began with the 2014 total U.S. non-coincident peak demand forecast of 771,944 MW.[89] To estimate the market potential of demand flexibility, we combined estimates for the total capacity of electric water heaters and air conditioning in the U.S.[90] For water heaters, using the NEEA end-use demand database we estimate that each unit has 5 kW of peak demand capacity, but that only 5.5% of connected water heater load is peak coincident (i.e., occurs between 2–8 p.m., June–September), to represent 1.6% of total U.S. peak load.

Air conditioning peak was calculated using FERC data from the 2009 A National Assessment of Demand Response Potential on residential demand and air conditioning saturation and peak demand.[91] For each state, we use FERC data for the number of residential customers, the average peak coincident residential demand, and AC saturation. We assume that during peak events where demand flexibility can be used to reduce system load, houses with AC units can shed 25% of total load.[xiii] Using this assumption along with the FERC data, we estimate a total reduction potential of 48.8 GW during peak events, or 6.3% of U.S. peak load.

We multiply the total savings potential (7.9%) by coincident peak demand, and adjust based on line losses and reserve margins to find the total capacity that can be avoided through reductions in peak end-use demand. We multiply this value by a conservative estimate of avoided costs for generation capacity, and add a similarly conservative avoided cost for transmission and distribution capacity, to arrive at the total avoided capacity costs of $9 billion per year.[xiv]

We calculated the value of LMP (locational marginal price) arbitrage using demand flexibility from DHW, AC, and electric dryers by analyzing the performance of each load in shifting energy from high-price to low-price hours using 2014 historical hourly price data from each of the seven organized energy markets in the United States.[xv] We take the average value of these savings, in dollars saved per MWh of end-use load, and scale to total end-use loads for each appliance using EIA RECS 2009 data, to arrive at the total energy cost savings of $3.3 billion per yr.

Contemporary research and pilot projects demonstrate that aggregated residential loads (including AC, DHW, and refrigerators) are technically capable of providing ancillary services to the grid, specifically frequency regulation and spinning reserve, in amounts far greater than needed.[92] We estimate the total U.S. market size for providing ancillary services using recent market survey data,[93] and scale the market size for the reported regions (CAISO, MISO, ERCOT, and PJM) using their respective fractions of total energy demand. We arrive at estimated market sizes of $710 million per year and $480 million per year for frequency regulation and spinning reserve, respectively.

These values represent the total potential avoided cost for capacity, energy, and ancillary services (frequency regulations and spinning reserve). Our analysis shows that implementing demand flexibility at scale can avoid these costs; however, these numbers do not incorporate the technology and/or program costs of demand flexibility, and thus do not represent the net benefits.

[xiv] Consistent with our model of A/C flexibility as well as an industry assessment of residential DR programs. For example, Freeman Sullivan Co.'s "2012 Load Impact Evaluation for Pacific Gas & Electric Company's SmartAC Program" found average savings of 24% for 2011 and 2012 events.

[xv] Data from Brattle, the California Public Utilities Commission, CAISO, EIA, PJM, Crossborder Energy, and Freeman, Sullivan and Co. reveal generation capacity values to range between $40/kW-year and $190.10/kW-year; we use the EIA's value of $91/kW-year. Transmission and distribution capacity savings range from $14/kW-year to $57.03/kW-year for distribution and $19.58/kW-year to $65.14/kW-year for transmission; we use a combined total of $27.3/kW-year.

[xvi] We use the energy component of LMP from each market, if available, to remove the impacts of transmission constraints and congestion. Where not available, we take a simple average across price zones or nodes within the market to estimate the system energy value.

APPENDIX B

DATA SOURCES AND ANALYSIS METHODOLOGY

APPENDIX B
DATA SOURCES AND ANALYSIS METHODOLOGY

We used NREL's System Advisor Model (SAM)[94] to calculate the levelized costs of rooftop solar. The table below lists the assumptions used in each case. For all scenarios except the Northeast load defection analysis, we assume a total installed cost of \$3.50/W_{dc} for the PV system,[95] and apply both the federal investment tax credit and MACRS offsets.

Note: All arrays have a tilt of 20 degrees and an azimuth of 180 degrees (south facing). LCOE models for each array used a discount rate of 8%.

The table below lists the weather stations used to model both PV production as well as air conditioning load for each building. We use typical meteorological year (TMY3) data to represent historical variability in weather.[96]

SOLAR ARRAY LCOE AND ENERGY MODELING CONSTANTS

LOCATION	ARRAY SIZE (kW_{AC})	CAPACITY FACTOR	STATE TAX RATE	SALES TAX RATE	LCOE REAL \$/KWH (2014\$)[xvii]
Alabama	4 kW	18.4%	6.5%	8.14%	\$0.1369
Arizona	6 kW	23.0%	6.0%	5.6%	\$0.0941
Hawaii	10 kW	20.3%	6.4%	4.0%	\$0.1042
New York	varies	16.2%	7.1%	8.47%	varies by year, see text

WEATHER STATIONS

	ALABAMA	ARIZONA	HAWAII	ILLINOIS	NEW YORK
Weather Station Location	Birmingham, AL	Phoenix, AZ	Honolulu, HI	Chicago, IL	White Plains, NY

[xvii] These values, presented in real dollars, are lower than what a contracted PPA price might show because they do not account for inflation.

LOAD MODELING

This section describes the energy data we use as well as the assumptions we make and the control strategies we use in order to model load flexibility for the five flexibility levers we analyze.

We use customized home energy models for each of our five U.S. regions. We modeled baseline customer usage behavior using select 15-minute submetered home energy data from the Northwest Energy Efficiency Alliance (NEEA),[97] collected between 2012 and 2013. We used this data to derive typical profiles for behavior-driven appliance use (hot water and electric dryers), as well as to derive estimates for non-flexible load in a typical home (e.g., television, cooking, lights, etc.). We chose one representative house with complete data that was closest to the median energy consumption for each flexible load, for all the homes in the data set. We then removed air conditioning and heating loads from the data set and added in our region-dependent base case air conditioning model to create the base case electric demand.

FLEXIBILITY MODELING METHODOLOGIES

The modeling approach for each flexible load is to shift kWh of electricity demand from high cost times to low cost times, where "cost" depends on the specifics of each modeled scenario (see below for specific modeling approaches used for each appliance in each location). We model load flexibility for each appliance over a full year in 15 minute increments in order to capture the impacts of changing weather, changing energy consumption, and changing solar production on load flexibility value.

Each flexible load has different constraints and operating requirements. Therefore we customize our approach for each appliance in order to optimize its electricity consumption. We detail each appliance's methodology and assumptions below.

DOMESTIC HOT WATER (DHW)

DHW DRIVING VARIABLES

POWER (MAX)	kWh STORAGE	TANK SIZE	MINIMUM AVERAGE TEMPERATURE	MAXIMUM AVERAGE TANK TEMPERATURE
7 kW	8 kWh	55 gallons	90 degrees F	150 degrees F

A flexible DHW system faces three main constraints: It needs to be able to provide hot water when the homeowner needs it, there is a limited amount of storage available in the hot water tank, and there is a limit to how much power the tank can draw. While a 55 gallon hot water tank heated from 60 to 150 degrees Fahrenheit can store 12 kWh of hot water, we assumed that the tank would maintain a minimum average temperature of 90 degrees Fahrenheit so that it could provide hot water at any time (water at the top of the tank is significantly hotter than tank average). This reduced the flexible storage available in the tank to 8 kWh. We limited the hot water tank's power draw to 7 kW based on assumed maximum electric service of 30 amps and 240 volts. We also assumed that the DHW system had a continuously variable heating element, based on interviews with manufacturers of technology that enable this capability. Using these assumptions, we applied an algorithm to ensure that the same number of kWh went into the hot water tank as were pulled out, and that there was always hot water on hand to meet demand.

AIR CONDITIONING (AC)

AC DRIVING VARIABLES

POWER	SET POINT	DEADBAND	PRE-COOLING MINIMUM TEMPERATURE	MAX INDOOR TEMP
6 kW	70 degrees F	3 degrees F	66 degrees F	74 degrees F

We use an AC load model to customize regional baseline AC energy consumption. This model is driven by a first-order, resistance-capacitance thermal model of a home and controlled by a temperature setpoint of 70 degrees Fahrenheit and a deadband of 3 degrees Fahrenheit.[98] We assume indoor temperature gains come from the building envelope as well as modeled solar heating gains from an EnergyPlus model of a typical home simulated in each climate zone we consider.[99] We used a combination of pre-cooling and thermal drift to shift AC energy use into lower cost times. We limited the precooling to 66 degrees Fahrenheit and we didn't allow the indoor temperature to exceed 74 degrees Fahrenheit. While we modeled allowing this setpoint increase for all high-cost hours of the year, our simulation of precooling limited the number of observed high-temperature events. For the ComEd and SRP scenarios, we did not observe any hours of increased temperature compared to the uncontrolled case. For the HECO scenario, we observed 27 hours per year of increased temperature with the control algorithm. For the Alabama Power scenario, we observed 47 hours per year of increased temperature.

Smart thermostats that enable flexible AC have also been proven to reduce both AC and heating energy use and associated costs. We do not account for reduced AC energy use, in order to avoid double-counting with the flexibility benefits. To model the heating costs savings for a typical customer with gas-fired space heat, we use the findings of Nest that their Learning Thermostat allows for 10% heating energy reduction on average.[100] We apply this 10% savings to the estimated space heating energy use for a typical home using the EnergyStar furnace calculator,[101] and convert to dollars by using EIA values for average delivered residential gas price.[102] These annual savings are reflected in our net cost estimates for AC demand flexibility.

ELECTRIC VEHICLE

EV DRIVING VARIABLES

POWER (MAX)	KWH USED PER DAY/USABLE BATTERY SIZE	MILES DRIVEN PER DAY
3.3 kW (level 1 charger)	10 kWh	30 miles

There are four main constraints that determine EV load flexibility potential: peak charge rate, daily vehicle energy use, battery capacity, and whether the vehicle is parked and plugged in. We assume that the EV charger was continuously variable from 0 to 3.3 kW, and that the vehicle uses 10 kWh of energy per day, yielding a usable battery capacity for demand flexibility of 10 kWh. We assumed a driving schedule for the car of 8 a.m. to 6 p.m. on weekdays, and 8 p.m. to 11 p.m. on weekends, with the car available for charging at all other times. The base case assumption for charging was to charge as quickly as possible at the start of the time parked. The optimized strategy delays charging until low-cost hours, while ensuring that the battery is 100% charged by the beginning of the next trip.

DRYER

We defined a "dryer cycle" as a continuous period with greater than 0 kWh of energy used for 15 minutes or longer, observed from the NEEA load database. Using dryer cycle data from the base-case dryer load profile, we allowed cycle start hours to shift by up to 6 hours forwards or backwards to optimize total cycle cost. We assume that this can be accomplished by a communicating switch on the dryer that would be able to start a cycle automatically when low-cost conditions exist, and/or simple behavior change from customers (however, we account for the present cost of the switch).

TECHNOLOGY COSTS & FINANCIAL ASSUMPTIONS

FLEXIBLE LOAD	MARGINAL COST	SOURCE
Air Conditioning (AC)	$225	Nest smart programmable thermostat cost of $250 minus the cost of a normal thermostat of ~$25[103]
Domestic Hot Water (DHW)	$200	Interviews with grid interactive water heater technology companies: Incremental cost of $200 covers additional capital cost and incremental installation costs, as well as possible license fees for patented technology
Electric Dryer	$500	Difference in price between a smart dryer ~$1,500 and an equivalent non-smart dryer ~$1,000[104]
Electric Vehicle (EV) Charging	$100	Interviews with industry experts: Hardware and software controls for remotely-controlled charging timing add approximately $100 to base-case charging equipment costs

The costs described above are the cost premiums to acquire these technologies today. We anticipate that with the increasing prevalence of connected devices and the "Internet of Things," connectivity for appliances in the future will be near-ubiquitous and enable demand flexibility at much lower incremental costs.[105]

APPENDIX C

SCENARIO-SPECIFIC ASSUMPTIONS AND RESULTS

APPENDIX C
SCENARIO-SPECIFIC ASSUMPTIONS AND RESULTS

The table below shows the data underlying the supply curves in the main text.

SCENARIO	LEVER	SHIFT COST $/kWh OR $/kW-MO	SHIFTED kWh OR AVOIDED kW-MO
ComEd	AC	-$0.11/kWh	191 kWh
	DHW	$0.02/kWh	1164 kWh
	Dryer	$0.20/kWh	330 kWh
	EV	$0.01/kWh	2061 kWh
	Battery	$0.25/kWh	2079 kWh
SRP	AC	$0.41/kW-mo	2.6 kW-mo
	DHW	$3.60/kW-mo	0.6 kW-mo
	Dryer	$16.76/kW-mo	0.32 kW-mo
	EV	$0.36/kW-mo	2.98 kW-mo
	Battery	$10.03/kW-mo	2.0 kW-mo
HECO	AC	$0.02/kWh	1640 kWh
	DHW	$0.02/kWh	1072 kWh
	Dryer	$0.14/kWh	472 kWh
	EV	$0.02/kWh	707 kWh
	Battery	$0.14/kWh	1740 kWh
Alabama Power	AC	-$0.17/kWh	338 kWh
	DHW	$0.00/kWh	1459 kWh
	Dryer	$0.32/kWh	200 kWh
	EV	$0.05/kWh	250 kWh
	Battery	$1.03/kWh	377 kWh

The tables below provide the data underlying the waterfall charts in the main text of the paper.

GLOSSARY OF TERMS

Energy Charge ($): The cost of energy purchased from the utility.
Customer Charge: A fixed utility charge to the customer regardless of energy use.
Demand Charge: A utility charge that is determined by the max kW of power demand by the customer.
Total DF Costs: The sum of all DF technology costs included for the scenario represented in each column.
PV Costs: The annual cost of the PV array.
Total: The sum of energy charge, customer charge, demand charge, DF costs, and PV costs.
Base: Base case costs with no DF and no solar PV.
+PV: Base case costs plus PV costs.
+[Flexibility lever]: All costs, including demand flexibility levers added in columns to the left, plus incremental costs and savings associated with this specific flexibility lever.

SCENARIO 1: ComEd

	DEFAULT RATE	RTP	+AC	+EV	+DHW	+DRYER	+BATTERY
Energy Charge	$1,840	$1,588	$1,568	$1,493	$1,441	$1,427	$1,332
Customer Charge	$183	$189	$189	$189	$189	$189	$189
Demand Charge		$358	$313	$241	$233	$233	$233
Total DF Costs			-$21[xvi]	-$8	$18	$83	$601
Total Costs	$2,024	$2,135	$2,049	$1,915	$1,881	$1,931	$2,354

ComEd modeling notes:

The load optimization strategy we use relies solely on energy prices, but also serves to reduce the demand charge that ComEd imposes on real-time pricing customers. ComEd assesses the demand charge in an annual, ex-post analysis of each customer's demand during the 5 hours of ComEd system peak coincident demand and the 5 hours of PJM system peak demand.[106] We analyze the impacts of our load control strategies on peak demand during these hours using 2014 data from PJM,[107] and find that a strategy driven by hourly prices also reduces coincident peak demand by 35%. This result is not surprising, since it is expected for wholesale prices (upon which ComEd's real-time prices are based) to spike during peak demand events.

[xvi] Negative costs indicate that the heating energy savings of AC outweigh the annualized capital costs of demand flexibility technology.

SCENARIO 2: SRP

	DEFAULT RATE	PV RATE (E-27)	EV	AC	+DHW	BATTERY	DRYER
Energy Charge	$2,640	$528	$511	$541	$537	$538	$537
Customer Charge	$240	$389	$389	$389	$389	$389	$389
Demand Charge		$1,917	$1,232	$746	$705	$594	$433
Total DF Costs			$13	$26	$52	$332	$397
Total PV Costs		$1,255	$1,255	$1,255	$1,255	$1,255	$1,255
Total Costs	$2,880	$4,089	$3,399	$2,956	$2,938	$3,109	$3,011

SCENARIO 3: HECO

	DEFAULT RATE	PV NON-EXPORT	+AC	+EV	+DHW	+DRYER	+BATTERY
Energy Charge	$8,572	$4,882	$4,550	$4,224	$3,667	$3,538	$2,882
Customer Charge	$108	$108	$108	$108	$108	$108	$108
Demand Charge							
Total DF Costs			$29	$42	$68	$133	$373
Total PV Costs		$1,291	$1,291	$1,291	$1,291	$1,291	$1,291
Total Costs	$8,680	$6,281	$5,978	$5,665	$5,134	$5,070	$4,655

SCENARIO 4: ALABAMA POWER

	DEFAULT RATE	PV RATE	AC	DHW	EV	+DRYER	+BATTERY
Energy Charge	$2,087	$1,559	$1,555	$1,413	$1,395	$1,395	$1,366
Customer Charge	$174	$424	$424	$424	$424	$424	$424
Demand Charge							
Total DF Costs			$(58)	$(58)	$(45)	$20	$408
Total PV Costs		$914	$914	$914	$914	$914	$914
Total Costs	$2,261	$2,897	$2,834	$2,693	$2,688	$2,753	$3,112

ALTERNATIVE SCENARIO: THE ECONOMICS OF LOAD DEFECTION, REVISITED

For the load defection analysis, we use a similar Northeastern region case study presented in our April 2015 report *The Economics of Load Defection*. We use the same range of Northeast utility electricity prices, the same PV cost trends, and the same assumed escalation rate of utility prices (3%/year). We used 2012 utility sales data from the U.S. Energy Information Administration (EIA) to identify the total amount of energy sold by utilities to residential customers in the region, including the decile distribution (i.e., tenths) of costs between high- and low-cost utilities. With the same (climate-adjusted) household consumption model used in the other scenarios of this paper, we then compared customers' lowest-cost option for grid-connected solar and solar-plus-demand flexibility systems to the range of utility retail per-kWh prices to determine what percentage of regional customers would be "in the money" with solar PV alone and PV-plus-flexibility throughout the region. Lastly, we multiplied the total energy consumed by the modeled customer by the optimal portion of load served by solar and solar-plus-flexibility systems and the per-kWh cost for each decile. This yielded the optimal sizing of PV arrays each year for customers in each decile, giving us the cost-effective rooftop PV market both with and without demand flexibility, as well as the maximum possible load defection (in MWh) the grid could see based on the economics of our analysis.

We assume excess PV is compensated at avoided cost, which we estimate using annual average locational marginal prices from NYISO from 2014 and escalate at 3% annually.[108]

SCENARIO-SPECIFIC LOAD MODELING METHODOLOGY

The table below highlights the specific load optimization approaches used in each scenario.

	DEFAULT RATE	RTP	+AC	+EV	+DHW
ComEd	Precooling and thermal drift strategies used to minimize consumption during high-cost hours	Defer water heating to minimize use during high-cost hours	Defer charging until lowest-cost hours	Choose lowest-cost cycle timing within 6 hours of original cycle start	Charge in lowest-cost hours and discharge in highest-cost hours
SRP	Precooling and thermal drift strategies used to minimize peak power demand	Defer water heating to minimize demand during peak period	Defer charging until after the peak demand period	When possible defer dryer use to prevent high peak demand	Charge during low demand and discharge during high demand
HECO, Alabama Power, and Load Defection	Precool and allow thermal drift in order to shift load into times of excess solar production	Time water heating to maximize on-site PV consumption while meeting hot water demand	Defer charging until periods of excess solar production	Defer cycle to consume as much solar as possible	Charge when excess solar and discharge so as to maximize solar self-consumption

APPENDIX D

SCENARIO MARKET SIZING

APPENDIX D
SCENARIO MARKET SIZING

To estimate the potential market for bill savings, solar installation, and controls investment that is unlocked by demand flexibility, we scale the results for our single, modeled customer premises to the potential market for other eligible utility customers served by the same utility.

PARTICIPATING CUSTOMER MARKET SIZING

For the ComEd scenario, there are roughly 10,000 customers already taking service under the analyzed RRTP rate. We scale our modeled results to these 10,000 customers after first scaling down the modeled savings and necessary investment to correspond to an average ComEd customer's annual consumption, estimated using EIA Form 861 data from 2013.[109]

NON-PARTICIPATING CUSTOMER MARKET SIZING

For all four scenarios, we estimate the number of customers who could achieve cost savings using demand flexibility by switching from default, volumetric rates to the rates analyzed. We use EIA Form 861 data to assess the number of customers who may be eligible to switch. For ComEd, this is the sum of all ComEd customers as well as customers of competitive electric suppliers whose electricity is delivered by ComEd.

For the other three scenarios, customers are only able to switch to the rates analyzed and achieve savings with demand flexibility if they install a rooftop PV system. We assume that only owner-occupied, single-family homes that have sufficient roof space to host PV panels are eligible to install PV. We use data from the U.S. Census on state-specific home ownership rates and the percentage of units that are multi-family,[110] and use NREL estimates of the potential for U.S. residential buildings to host at least 1.5 kWdc of rooftop PV capacity (81%) and the average size of installed rooftop PV (4.9 kW_{dc}).[111] We multiply EIA Form 861 records for the number of residential customers for each utility by these derating factors to arrive at an estimate of the number of potential PV-adopting customers in each jurisdiction.

To estimate the net bill savings potential, we scale our modeled customer's savings to utility-specific average consumption levels for residential customers. To estimate the solar PV market enabled, we multiply the average PV array size from NREL by the number of eligible houses, and convert to dollars using the assumed installation price for residential PV of $3.50/$W_{dc}$. To estimate the vendor market, we scale the total capital cost of all cost-effective flexibility measures for our modeled customer in each scenario by the ratio of average to modeled customer consumption.

For scenarios 1 and 2, we also estimate the utility-wide peak demand reduction potential unlocked by residential DF. We estimate the percentage peak demand reduction realized using our model during either system coincident peak (ComEd) or on average across all peak periods each month (SRP), and multiply that peak reduction by residential customer average peak demand using data from the 2009 FERC National Assessment of Demand Response Potential.[112]

ENDNOTES

ENDNOTES

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