COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company and Nantucket Electric Company in their petition for approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq	)	**D.P.U. 15-155**

Direct Testimony of

Tim Woolf and Melissa Whited

On behalf of

The Energy Freedom Coalition of America, LLC

Regarding Rate Design

March 18, 2016

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and employer.

A. **Woolf:** My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

A. **Whited:** My name is Melissa Whited. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency (EPA), U.S. Department of Energy (DOE), U.S. Department of Justice, the Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. **Woolf:** Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU) for four years. In that capacity, I was responsible for overseeing a substantial expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of the DPU energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; review and approval of smart grid pilot programs; and review and approval of long-term contracts for renewable power. I was also responsible for overseeing a variety of other dockets before the Department, including several electric and gas utility rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director at the Association for the Conservation of Energy; a Staff Economist at the Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Masters in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University. My resume, attached as Exhibit 1, presents additional details of my professional and educational experience.

A. **Whited**: I have six years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models, rate design, policies to address distributed energy resources, and market power. My recent publications and presentations include a report and webinar on the impacts of fixed charges, a presentation on utility performance incentive mechanisms to the National Governor's Association Learning Lab on New Utility Business Models, a presentation to the Utah Net Energy Metering Workgroup on rate design options to address net energy metering, and a report on benefit-cost analysis for distributed energy resources filed in New York's Reforming the Energy Vision proceeding. I have assisted in developing testimony or comments in decoupling proceedings in Hawaii, Maine, and Nevada, and have analyzed rate design issues pertaining to distributed energy resources for proceedings in New York, Utah, Nevada, Wisconsin, Hawaii, and Maryland.

I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. Prior to rejoining Synapse, I published in the Journal of Regional Analysis and Policy regarding the economic impacts of water transfers, analyzed state water efficiency policies while at the Wisconsin Public Service Commission, and conducted econometric analyses of energy efficiency cost-effectiveness. I also testified before the Wisconsin Senate Committee on Clean Energy regarding the economic impacts of clean transportation options and presented to the Wisconsin Public Service Commission regarding the state's electricity demand response programs and potential. My resume is attached as Exhibit 2.

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of the Energy Freedom Coalition of America, LLC ("EFCA"), a for-profit LLC. EFCA represents a variety of companies that provide goods and services relating to distributed energy resources, including solar and battery storage. Current EFCA participants include Silevo, Inc., SolarCity Corporation, ZEP Solar, LLC and NRG Energy, Inc., some of whom have centers of operation and employees who live and work in Massachusetts, including in its Gateway cities.

Q. Why is EFCA intervening in this docket?

A. EFCA participants employ a number of former utility grid engineers and economists who offer an informed and unique perspective on how proposed agency actions may impact the distributed energy resources markets in which they engage. In particular, EFCA members possess strong interests in insuring that regulatory proceedings regarding rate design and distribution planning utilize the integration of distributed energy resources (DERs) and technologies, which help provide system benefits and reduce utility costs overtime. These goals coincide with the Commonwealth's interests in showing leadership in the storage market, which the Commonwealth recently called a "game changer that can play a part in solving our energy challenges."[1] With the Department of Energy Resources' $10 million Energy Storage Initiative, [2] the Commonwealth is "position[ing] itself to grab a disproportionate share of the economic opportunities arising out of the fast growing global markets for storage technology." As the Governor himself recently noted: "The Commonwealth's plans for energy storage will allow the state to

[1] *See* **DOER Commissioner Judith Judson, December 8. 2015, Presentation to ACEEE Intelligent Efficiency Conference,** ***available at*** https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&ved=0ahUKEwiJi7CPosrLAhWKez4KHTrAC0YQFggkMAE&url=http%3A%2F%2Faceee.org%2Fsites%2Fdefault%2Ffiles%2Fpdf%2Fconferences%2Fie%2F2015%2FTuesday%2520Plenary-Judson-IE15-12.8.15.pdf&usg=AFQjCNF7ij6YFUORM0xw2QRZyVD3bokevg&sig2=rFT4JCB4x7YyQDt_BhfS4w, **Slide 11.**

[2] **The Energy Storage Initiative is described at** http://www.mass.gov/eea/pr-2015/10-million-energy-storage-initiative-announced.html.

move toward establishing a mature local market for these technologies that will, in turn, benefit ratepayers and the local economy."

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address National Grid's (the Company) proposed rate design, and its implications for the development of distributed generation and storage technologies in Massachusetts. Our testimony discusses the Company's proposal to establish tiered customer charges for residential and small commercial and industrial customers, to establish demand ratchets for medium and large commercial and industrial customers, and to eliminate the time-of-use energy rate for large commercial and industrial customers. Greenlink is providing testimony on behalf of EFCA regarding the Company's proposed Access Fee for stand-alone generators.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your overarching conclusions.

A. The Company is proposing some dramatic modifications to rate design that are inconsistent with the Department's goals and precedents on these issues, without sufficient justification for doing so. The Company's proposal will not improve customer equity as claimed, will hinder the development of distributed generation and storage technologies, will harm low-usage and low-income customers more than others, and could ultimately increase electricity costs for all customers over the long-run.

Q. Please summarize your specific conclusions regarding the Company's rate design proposals for residential and small commercial and industrial customers.

A. Our conclusions regarding the Company's tiered customer charges for residential and small customers are as follows:

1. The tiered customer charges conflict with the Department's goal of customer fairness.
    - The Company's proposal to use the highest month of consumption to set the tiered customer charges does not represent demand costs any better than the current rate design.
    - The tiered customer charges are regressive, as they disproportionately impact low- and moderate- usage customers, who tend to be low-income customers.
    - The Company has not demonstrated that distributed generation customers are not paying their "fair share" of the distribution costs. Such a demonstration requires a complete assessment of both the costs and the benefits of distributed generation.
2. The tiered customer charges conflict with the Department's long-standing, clearly-articulated goals of efficiency and the promotion of efficient price signals.
    - Higher fixed charges send customers the signal that their energy usage matters less, which diminishes customer incentives to reduce energy consumption.
    - Efficient price signals should reflect the long-run marginal costs of operating the electricity system, where all costs are essentially variable. This requires that fixed customer costs should remain low, and only reflect the costs associated with incremental costs of serving the customer.

- The Company's tiered customer charges fix a customer's maximum customer charge for a period of 12 months. This discourages customers from reducing energy consumption during those 11 non-peak months.
- Price signals can only be efficient if the customer has the ability to respond in an efficient fashion. However, it will be very difficult, if not impossible, for residential and small commercial customers to understand, monitor, and respond to the tiered customer charges.

3. The tiered customer charges conflict with the Department's goal of continuity, as the Company's proposal would increase residential customer charges by up to 400 percent, and small commercial customer charges by up to 200 percent.
4. The tiered customer charges conflict with the Department's goal of simplicity, because they would not be confusing to many customers, and customers will not have the information they need to respond to the customer charges.
5. The tiered customer charges conflict with the Department's grid modernization goals, which encourage the distribution companies to enable customers to optimize their consumption patterns through energy efficiency, distributed generation, and other demand resources.

Q. Please summarize your primary conclusions regarding the Company's rate design proposals for medium and large commercial and industrial customers.

A. Our conclusions regarding the Company's rate design proposals for medium and large commercial and industrial customers are as follows:

1. The proposed demand ratchets have nearly the same effect on customers as increased fixed customer charges, and therefore conflict with the Department's goals of efficiency and efficient price signals.

2. The proposed demand ratchets significantly reduce customer incentives to install storage and other demand resources, and therefore conflict with the Department's goals of efficiency and efficient price signals.

3. The proposal to eliminate the on-peak time-of-use energy charge and replace it with a higher on-peak demand charge for G-3 customers provides customers with no incentive to reduce load during off-peak hours, and could also lead to the creation of new peaks during off-peak hours, therefore conflicting with the Department's goals of efficiency and efficient price signals.

4. The Company's proposal to increase the G-3 customers' demand charge by 79 percent conflicts with the Department's goals of continuity.

Q. Please summarize your recommendations.

A. We offer the following recommendations:

1. The Department should reject the Company's proposal for tiered customer charges for R-1, R-2, and G-1 classes. Further, the Department should not increase the current customer charges for these customers by any more than the percentage increases that are applied to the energy charges for these classes to attain the class revenue requirements allowed by the Department in this docket.

2. The Department should reject the Company's proposal to introduce ratchets for any customers, whether through the tiered customer charge for small customers, or through a demand ratchet for G-2 and G-3 customers.

3. The Department should reject the Company's proposal to increase the demand related charges for G-3 customers.

4. The Department should refrain from entertaining proposals to significantly modify current rate designs absent resolution of on-going developments from the Department's prior orders regarding time-varying rates and advanced metering infrastructure.

5. The Department should articulate that if the Company wishes to make significant modifications to rate design practices on the grounds of customer equity and cost-shifting from distributed generation customers, it must first conduct a thorough quantitative analysis of any cost shifting, which should include all relevant costs and benefits of distributed generation resources.

3. NATIONAL GRID'S RATE DESIGN PROPOSAL

Residential and Small Commercial Rate Design

Q. What rate design changes does National Grid propose for the residential and small commercial classes?

A. National Grid has proposed a two-phased approach to adjusting rates for the residential and small commercial classes. In Phase I, the Company proposes to eliminate the upper block for the energy charge and increase the residential customer charge by 38 percent.

In Phase II, National Grid proposes to introduce tiered customer charges that increase the residential customer charge up to 400 percent, and increase the small commercial customer charge up to 200 percent. These increases are shown in the table below.

Table 1. Proposed Increase in Customer Charges

		Proposed Customer Charges	% Increase Over Current Charge
R-1 / R-2 / E	Phase I	$5.50	38%
	Phase II - Tier 1	$6.00	50%
	Phase II - Tier 2	$9.00	125%
	Phase II - Tier 3	$15.00	275%
	Phase II - Tier 4	$20.00	400%
G-1	Phase I	$10.00	0%
	Phase II - Tier 1	$10.00	0%
	Phase II - Tier 2	$11.00	10%
	Phase II - Tier 3	$15.00	50%
	Phase II - Tier 4	$30.00	200%

Q. Please explain how the Company proposes to assign customers to a tier?

A. The Company proposes that residential and small commercial customers be assigned to a tier based on a customer's highest month of usage in a 12-month period. That is, the customer charge will be assessed based on the total energy used in the month in which the customer's highest billed usage occurs. The Company proposes to set the tiers as follows:[3]

[3] Direct Testimony of Pricing Panel, Exhibit NG-PP-1, page 65 of 89.

	Usage Range	Proposed Customer Charges
R-1/R-2/E	0 - 250 kWh	$6.00
	251 - 600 kWh	$9.00
	601 - 1,200 kWh	$15.00
	> 1,200 kWh	$20.00
G-1	0 - 75 kWh	$10.00
	76 - 500 kWh	$11.00
	501 - 2000 kWh	$15.00
	> 2,000 kWh	$30.00

For example, if a residential customer typically consumes 400 kWh per month but uses 601 kWh in one month, the customer will automatically move into Tier 3, which has a customer charge of $15.00 per month, as opposed to $9.00 a month, if the customer remained in Tier 2.

Q. How will a customer move into a lower tier?

A. A customer will move into a lower tier only after 11 consecutive months of demonstrating usage below the tier threshold.[4] In effect, the tiered customer charge acts as a "ratchet," where a customer can automatically move into a higher tier, but must wait a year before moving into a lower tier. The Company is also expressly proposing a demand ratchet for G-2 and G-3 customers, as discussed below.

Q. Is the dramatic increase in customer charges due to commensurate increases in customer-related costs?

A. No. The increase in the customer charge is due to the Company redefining the purpose of the customer charge.

[4] Nat'l Grid, Resp. to Information Req. AG-12-6, Feb. 4, 2016.

Q. Please explain what you mean by "redefining the purpose of the customer charge."

A. The customer charge has historically been intended to recover customer-related costs. The Company now proposes to use the customer charge to recover a portion of demand-related costs as well.[5]

Q. What is the Company's rationale for recovering demand-related costs through tiered customer charges?

A. The Company asserts that its primary rationale for its proposed rate design is to improve equity among customers by implementing rates that better reflect cost causation. Specifically, the Company argues that its rate design will move toward rates that are "fair and equitable across all customers and are designed to reflect the actual relative cost to serve each customer, both those with and without DG."[6]

In addition to fairness and equity, the Company refers to the goals of cost recovery and efficiency, stating that it seeks to balance the objectives of "appropriately recovering the cost to operate, maintain and invest in the distribution system, and encouraging customers to become more efficient in their total electricity usage."[7]

The Company's proposed rate design fails to accomplish any of these goals, as discussed below.

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[5] Prefiled Testimony of the Pricing Panel, page 33, line 3.
[6] *Id,* page 23.
[7] *Id,* page 45.

Medium and Large Commercial and Industrial Rate Design

Q. What rate design changes does National Grid propose for the G-2 and G-3 customer classes?

A. The Company proposes to recover more of G-2 and G-3 customers' revenue requirement through customer charges and demand charges, which will employ a "ratchet."

	Rate Element	Current	Proposed	Change
G-2	Customer Charge	$16.56	$25.00	51%
	Demand Charge	$6.00	$8.50	42%
	Energy Charge	$0.00078	$0.00323	314%
G-3	Customer Charge	$200.00	$223.00	12%
	Demand Charge - Peak	$3.92	$7.00	79%
	Demand Charge – Off-Peak	$0.00	$0.00	0%
	Energy Charge - Peak	$0.00753	$0.00000	N/A
	Energy Charge – Off-Peak	$0.00000	$0.00000	0%

Q: Please explain National Grid's justification for eliminating the energy charge for G-3 customers.

A: The Company proposes to eliminate the on-peak energy charge and recover all base distribution costs through the customer and demand charge in order to provide customers with better price signals to shift demand and flatten their load curves.

Q. Please describe how the demand ratchet would operate.

A. Instead of assessing customers a demand charge based on their highest demand during the month, the demand charge would be based on the higher of the customer's demand (in kW or 90 percent of the metered kVa) during the month, or 75 percent of the highest demand during the prior 11 months (as defined previously). Thus, if a customer's demand briefly increased due, for example, to an equipment failure, a new peak could be set that would determine the customer's demand charge for that month and the next 11 months.

Q. What is the Company's rationale for implementing a demand ratchet?

A. The Company argues that a demand ratchet will better reflect cost causation, as "assessing demand charges based upon each customer's maximum demand during the year will better reflect that customer's contribution to the aggregate, or coincident, demand, and will result in a recovery of costs that is more commensurate with cost causation."[8] However, this argument is flawed, as we describe below.

4. RATE DESIGN GOALS

Q. What are the Department's rate structure goals?

A. In its order issued in National Grid's most recent rate case, the Department articulated the following rate structure goals: efficiency, simplicity, continuity of rates, fairness between rate classes, and corporate earnings stability.[9]

Q. Are the Department's goals consistent with rate design goals used elsewhere in the electricity industry?

A. In general, yes. The Department's goals are consistent with the principles put forth by Professor Bonbright,[10] which most states draw from in designing rates. These principles are reproduced in Exhibit 3.

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[8] *Id,* page 56 of 89

[9] Massachusetts DPU, Order in *Petition of Massachusetts Electric Company and Nantucket Electric Company, pursuant to G. L. c. 164, § 94, and 220 C.M.R. § 5.00 et seq., for a General Increase in Electric Rates and Approval of a Revenue Decoupling Mechanism,* D.P.U. 09-39, November 30, 2009 ["DPU 09-39"], p. 401.

Q. Please elaborate on the goal of efficiency.

A. The goal of efficiency can best be achieved by providing customers with efficient price signals. Efficient prices will encourage customers to optimize their electricity consumption patterns through conservation or demand resources, such as energy efficiency, demand response, distributed generation, electricity storage, and more. Sending efficient price signals has always been a very important goal, and it is becoming increasingly important as customers are being provided with increasing opportunities to optimize their consumption through demand resources.

Q. How is the goal of efficiency defined?

A. In its last National Grid rate case order, the Department noted that:

- "[T]he design of distribution rates should be aligned with important state, regional, and national goals to promote the most efficient use of society's resources and to lower customers' bills through increased end-use efficiency."[11]
- Efficiency means that "rate structures provide strong signals to consumers to decrease excess energy consumption in consideration of price and non-price social, resource and environmental factors." [12]

In addition, Professor Bonbright's principle of "discouraging wasteful use of service" addresses the heart of the principle of efficiency.

[10] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.
[11] DPU 09-39, pp. 423-424.
[12] DPU 09-39, pp. 401-402.

Q, What is the best way to send efficient price signals?

A. Price signals will be efficient if they reflect the long-run marginal costs of operating the electricity system. Customers who are made fully aware of long-run marginal costs through their electricity prices will be able to make decisions regarding their on-going electricity consumption that will help to minimize the long-run system costs. When long-run system costs are minimized in this way, all customers benefit.

Q. The Company argues that, once constructed, distribution system costs are fixed.[13] How does this relate to the concept of setting rates based on long-run marginal costs?

The terminology for fixed costs and variable costs is frequently confused, because the types of costs that are used for determining revenue requirements are different than the types of costs used for designing rates.

- Revenue requirements should be based on historical costs because this will ensure that the utility recovers the costs that it has already incurred. Historical costs are defined as either variable (e.g., fuel costs) or fixed (e.g., capital costs of distribution facilities), and these definitions are used to allocate costs based on cost causation.

[13] Prefiled Testimony of the Pricing Panel, page 33.

> -Rate design should be based on future costs, because these are the costs that are relevant for sending efficient price signals to customers: customers should receive price signals that encourage them to minimize future costs. For this purpose, future costs should be defined as entirely variable.

Professor Bonbright provides a lengthy discussion of the importance of sending price signals based on future long-run marginal costs. He concludes this discussion with the following summary:

> . . . [A]s setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety—of a variety which treats even capital costs or "capacity costs" as variable costs.[14]

In other words, for the purpose of sending efficient price signals in rate design, in the long-run all costs – including the costs of the distribution system – should be considered variable and avoidable.

Q. Please explain what this means for setting distribution system rates.

A. A utility's revenue requirement should be sufficient to recover its historical costs, as this is necessary to ensure that the utility recovers its costs plus the opportunity to earn a fair return. However, a utility's rate designs should be based on future costs, as this will allow customers to control their consumption in a way that minimizes those costs.

Thus, while a class's revenue requirement should be designed to recover historical costs, rates should be set to send a clear price signal that reflects the long-run marginal costs associated with increased usage of the system. For example, greater usage of the system

[14] James Bonbright (1961), *Principles of Public Utility Rates*, Columbia University Press, page 336.

will cause the utility to invest in additional capacity, and may cause equipment to wear out faster. If customers are provided with variable rates that reflect these costs, they can choose to reduce their usage of the system to avoid these costs. In contrast, if revenues are recovered through fixed charges or demand ratchets, customers are sent an inaccurate price signal that their usage does not affect distribution system costs.

Q. Please elaborate on the goal of fairness.

A. The Department explains that fairness means that "no class of customers should pay more than the costs of serving that class."[15] This is essentially the same as Professor Bonbright's principle of "equitable apportionment of costs among customers."

Professor Bonbright offers an additional principle that rate designs should avoid "undue discrimination" in rate relationships.[16] This means that customers who receive comparable types of services should be provided comparable rate designs and pay comparable bills.[17]

Q. Do demand resources introduce a new dimension to the concept of customer fairness and equity?

A. Yes. Historically, customers have primarily imposed costs on the utility system, and rates have been designed to properly recover those costs. However, demand resources introduce a new dimension to customer equity considerations because demand resources

[15] DPU 09-39, p. 402.

[16] James Bonbright (1961), *Principles of Public Utility Rates*, Columbia University Press,, page 291.

[17] Bonbright notes that there are many forms of discrimination in rate relationships (some of which are "due," while others are "undue," and that it is impossible to avoid them all. One definition of discrimination offered by Bonbright is the economic definition, which holds "that the practice of exacting different charges for different classes of service rendered at the same marginal costs constitutes discrimination, and… that failure to impose higher charges for services rendered at markedly higher marginal costs is also discriminatory." *Id.,* page 374.

create system benefits as well as costs. These benefits include avoided distribution costs, avoided transmission costs, reduced costs of capacity purchases from the New England wholesale electricity markets, and the suppression of prices in the New England wholesale electricity markets.

Q.

What benefits are provided by customers that install DG or other demand resources?

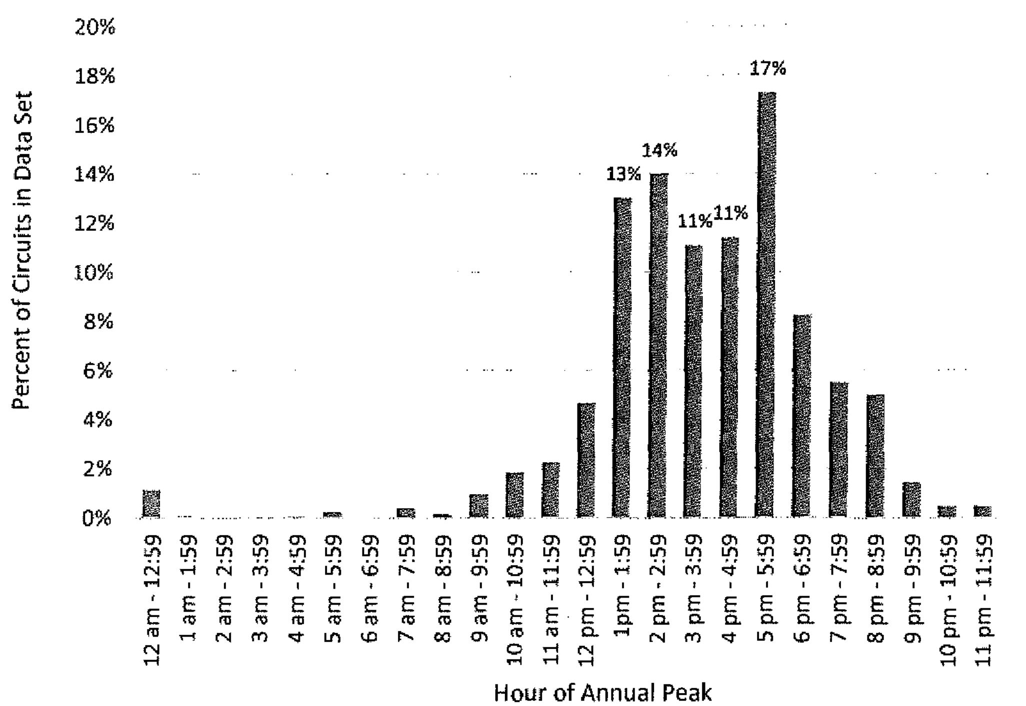
A. Experience demonstrates that customers who install distributed generation or other demand resources, such as storage, provide benefits to the utility system in terms of avoided distribution costs, avoided transmission costs, reduced costs of capacity, and the suppression of prices in the wholesale electricity markets.[18] These reduced costs then translate into lower revenue requirements for distribution utilities and lower costs of generation for all customers. These benefits provided by DG could be significant.[19] Benefits specific to National Grid's distribution system may include the ability to defer distribution system upgrades, particularly on feeders that are approaching the need for upgrades, potential reliability and power quality improvements, as well as reduced stress on equipment (e.g., transformer overheating) during system peaks. For example, the Company's distribution circuits tend to experience peak loads during summer afternoons, particularly during the hours of

[18] See, for example, SolarCity (2016) *A Pathway to the Distributed Grid*, available at http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf, and attached hereto as Exhibit

[19] See, for example, two recent studies on the Value of Solar in New England: Acadia Center (2015) *Value of Distributed Generation: Solar PV in Massachusetts,* available at http://acadiacenter.org/document/value-of-solar-massachusetts/; *and* Norris, B., P. Gruenhagen, Grace, P. Yuen, R. Perez, and K. Rabago (2014) *Maine Distributed Solar Valuation Study.* Prepared for the Maine Public Utilities Commission. Available at http://www.nrcm.org/wp-content/uploads/2015/03/MPUCValueofSolarReport.pdf.

1 pm through 5 pm.[20] These summer afternoon hours correspond reasonably well to solar output, particularly west-facing systems, and may allow the Company to defer or avoid distribution capacity upgrades, benefitting all customers through reduced revenue requirements.

Figure 1. Hour of Annual Peak for National Grid Circuits



To determine whether customers employing demand resources are paying their "fair share" of distribution system costs, one cannot look at the reductions in the customer's bill alone. One must also consider the system benefits provided by that customer.

[20] Based on data for 328 circuits for the years 2012-2015, provided in response to VS-02-012. 97 percent of these peak hours were during the months of June through September.

Q. But the Company asserts that distributed generation resources will result in cost-shifting to non-DG customers. How do the benefits of distributed generation resources affect any cost-shifting that might occur?

A. The Company has claimed several times in this docket that DG customers will shift costs to non-DG customers, and that this will be an inequitable outcome. In fact, this is the primary rationale that the Company provides for its proposed tiered customer charges.[21] However, this view does not account for the fact that the benefits of distributed generation will off-set cost-shifting.

Q. Please explain how the benefits of distributed generation will offset cost-shifting.

A. As a customer's self supply of electricity reduces his or her need for electricity from the grid , cost-effective distributed generation can appear to result in cost-shifting because of the "lost revenues" the Company would have collected from customers if not for the reduced sales resulting from the distributed generation. When lost revenues are recovered from all customers, they create upward pressure on rates (all else being equal), which results in an apparent "shifting" of the recovery of historical costs from the DG customers to the other customers. (For this reason, I prefer to use the term "revenue-shifting," because it is more accurate than the term cost-shifting.)

[21] The Company claims that, under the current rate design, "DG customers may contribute significantly less to support the distribution system as a result of their reduced kWh usage, thereby shifting the recovery of distribution system costs to all non-DG customers." Pricing Panel prefiled testimony, page 28. Further, the Company states that its rate design proposals are intended "to ensure that customers who reduce kWh consumption either through implementation of DG or energy efficiency will pay their fair share of the Company's distribution system." Pricing Panel, page 64.

However, the system benefits of demand resources will have the countervailing effect of putting downward pressure on electricity rates by reducing the costs to all customers of distribution, transmission, and purchases from wholesale electricity markets. These benefits will reduce or eliminate any revenue-shifting that might occur as a result of distributed generation, and could even lower distribution rates for all rate payers in the long term.

Q. How do you recommend that concerns about cost-shifting, or revenue-shifting, be addressed in rate design?

A. In order to promote customer equity and fairness, it is essential to fully understand whether any revenue-shifting is occurring, and to use analyses that account for both the costs and benefits created by customers. To completely ignore the benefits provided by certain customers would skew the determination of what is fair, and would discriminate against those customers who provide benefits to the system. It would also create disincentives for customers to provide those benefits in the first place—depriving all customers of those benefits.

Q.

Q. Please elaborate on the goal of simplicity.

A. The Department notes that simplicity means that the rate structure is "easily understood by customers." Professor Bonbright includes simplicity in combination with the related attributes of "understandability, public acceptability and feasibility of application."

It is important to note that the goal of simplicity is closely linked to the goal of efficiency and efficient price signals. The rate design must be simple and clear enough to enable a customer to optimize his or her energy consumption patterns. If, for example, a utility wishes to encourage a customer to reduce his or her contribution to peak demand on the system, then the rate design must be simple and understandable enough to encourage modified behavior *at the time of system peak demand.*

In addition, simplicity may need to be defined differently for different types of customers. For example, large industrial customers, with high energy costs and in-house energy managers, will be able to understand and respond to more complex prices signals than small commercial, residential, and low-income customers.

Q. Please elaborate on the goal of rate continuity.

A. The Department notes that rate continuity means that "changes to rate structure should be gradual to allow customers to adjust their consumption patterns in response to a change in structure."[22] Professor Bonbright defines this goal as the "stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers."[23]

Q. Please elaborate on the goal of corporate earnings stability.

A. The Department notes that earnings stability means that "the amount a company earns from its rates should not vary significantly over a period of one or two years."[24] Professor Bonbright offers two related principles: that rate design should achieve: (a) effectiveness

[22] DPU 09-39, p. 402.
[23] James Bonbright (1961), *Principles of Public Utility Rates*, Columbia University Press, page 291.
[24] DPU 09-39, p. 402.

in yielding total revenue requirements under the fair-return standard; and (b) revenue stability from year to year.[25]

It is important to recognize that this principle is not at issue in this case, as the practice of decoupling (a) has significantly improved revenue stability for the Company, and (b) ensures that the Company will recover its allowed revenue requirements regardless of which rate design proposal is adopted.

5. CUSTOMER EQUITY AND TIERED CUSTOMER CHARGES

<u>The Proposed Proxy for Demand is no Better than an Energy Rate</u>

Q. Please explain how the tiered customer charge is intended to achieve the Company's rate design objectives.

A. The Company's preferred rate structure for residential and small commercial customers would consist of a combination of a fixed customer charge and a demand charge. However, until advanced metering is in place, it does not have the capability of assessing a demand charge based on kW demand, and has instead developed a tiered customer charge based on a customer's highest month of energy usage as a "reasonable proxy" for a demand charge.[26]

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[25] James Bonbright (1961), *Principles of Public Utility Rates*, Columbia University Press,, page 291.
[26] Nat'l Grid, Resp. to Information Req. EFCA-1-1, Feb. 9, 2016, and DPU-32-32, Mar. 7, 2016.

Q. Why does the Company wish to implement a demand charge?

A. The Company states that its distribution system "is sized and constructed to accommodate the maximum demand that occurs during periods of greatest demand…."[27] For this reason, the Company seeks to design rates that account for a customer's maximum demand on the system.

Q. Will the Company's proposal improve customer equity?

A. No. The Company's proposal will not result in more equitable rates because it does not more accurately reflect cost causation for two reasons:

- First, neither a customer's highest month of usage nor maximum hourly usage reflect the coincidence between customer demand and distribution system peaks.
- Second, the Company has not demonstrated that the tiered customer charge based on a customer's highest month of energy use is a better indicator of a customer's maximum demand than current volumetric rates based on energy usage. In fact, the Company's own data indicates that a customer's highest month of usage is a worse indicator of a customer's maximum demand on the system than average energy usage.

[27] Prefiled Testimony of Pricing Panel, Exhibit NG-PP-1, Page 33 of 89, lines 12-14.

Q. Is it true that a customer's maximum demand during any one time period is indicative of the costs imposed on the system by that customer?

A. No. Many small customers typically share distribution system equipment,[28] and thus diversity of load must be accounted for. As the Company explains, "Because an individual customer's peak usage typically does not occur at the exact same time as their neighbors," the Company designs its system to recognize this diversity "from the design of the distribution transformer level up to the design of the size of the primary conductor (or feeder) serving the distribution transformer, and also from the feeder to the local substation transformer."[29] Thus, a customer's individual peak demand will ordinarily not put the greatest strain on the system.

Q. Is it therefore important to account for the timing of a customer's demand?

A. Yes. As the Company explains, "Encouraging customers to shift load from high use, peak periods into off-peak periods through demand management 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 has to serve peak loads. … Better utilization of the system also reduces the need to build additional system capacity to meet peak loads, as these peak loads occur for only as few as 20 hours to as many as a few hundred hours per year. Given the high fixed costs in the industry, reducing capacity requirements may ultimately result in reduced distribution system investment for capacity

[28] The Company states that 8 to 10 small customers (100 amp service) can be served by a single 25 kVa transformer, and a typical 15 kV class feeder may serve up to 3,000 customers or more. *See* Nat'l Grid Resp. to Information Req. DPU-9-13, Jan. 22, 2016.
[29] *Id.*

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reasons, and, ultimately, a lower future cost to be recovered from customers than would otherwise be incurred."[30]

Q. Do tiered customer charges account for the timing of a customer's demand on the system?

A. No. The tiered customer charges are based on the highest month of energy usage over a 12-month period,[31] and do not reflect a customer's actual peak demand or the timing of that demand.

Q. Does a customer's highest month of energy usage better reflect demand on the system than average energy usage?

A. No. In fact, for residential customers, the proposed proxy for a customer's maximum demand (highest month of usage) is a slightly worse indicator than average monthly usage. That is, the correlation between average energy usage and a residential customer's maximum demand is *greater* than between a customer's highest month of usage and maximum demand.

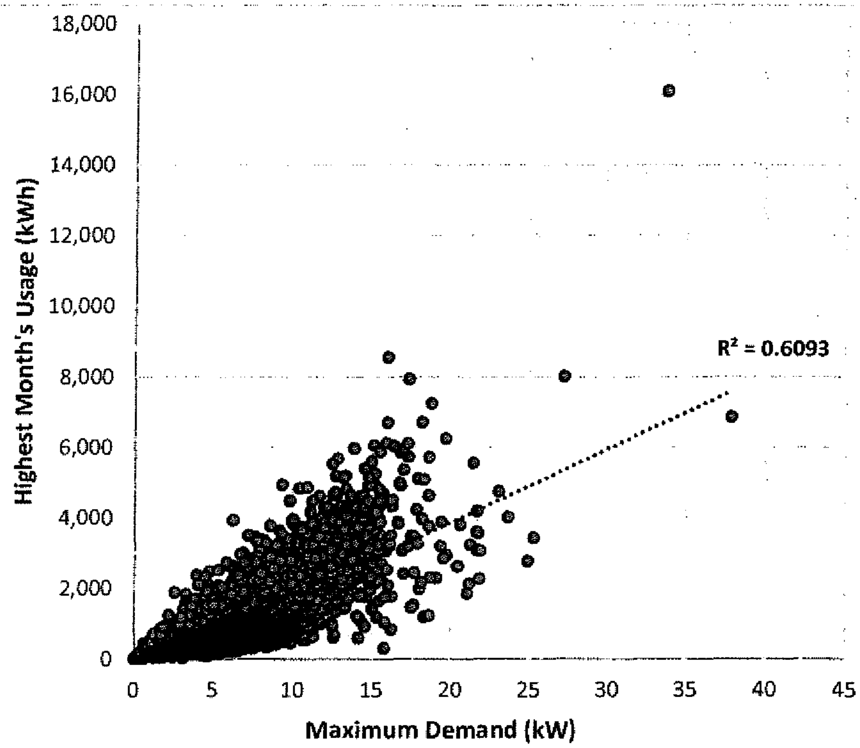
Q. Have you analyzed any data regarding highest month of usage and customer demand?

A. Yes. In Exhibit NG-PP-10, the Company provided a graph showing the correlation between a customer's highest month of usage and that same customer's maximum demand. A perfect correlation between the two variables would result in a coefficient of

[30] Prefiled Testimony of Pricing Panel, Exhibit NG-PP-1, Page 30, lines 9-21.
[31] *Id*, Page 33, lines 4-6.

determination (R^2) of 1.0.[32] According to the Company's analysis, the relationship between a customer's highest month of usage and a customer's maximum demand exhibits a coefficient of determination (R^2) of 0.6093. We have reproduced this graph below.[33]

Figure 2. Relationship between Customers Highest Month of Usage and Maximum Demand



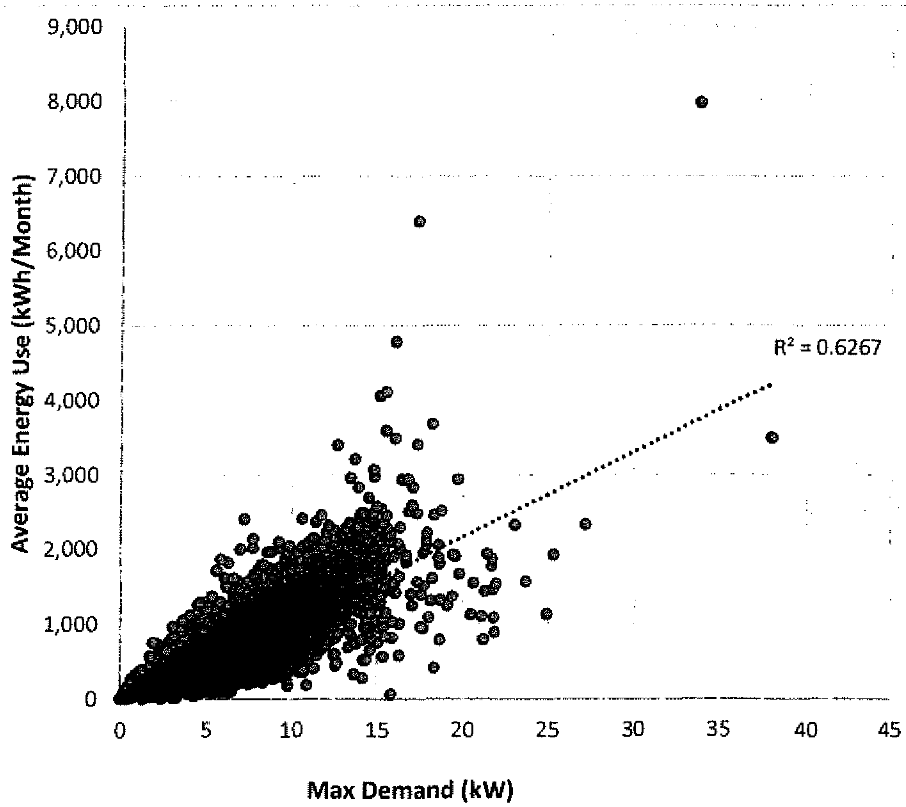
Using the same underlying data set, we also graphed the relationship between a customer's average monthly usage and the customer's maximum hourly load. The result was very similar to the Company's, with a slightly higher correlation between average

[32] The R^2 statistic represents how much of the underlying data variability is explained by the model. In this case, the R^2 statistic can be interpreted as how good of an indicator a customer's monthly maximum usage is for a customer's maximum hourly demand.

[33] For clarity, this graph uses slightly different axis titles than those originally used by the Company.

energy usage and maximum demand. This is shown in the graph below, with a coefficient of determination (R^2) of 0.6267.

Figure 3. Relationship between Customers' Average Energy Usage and Maximum Demand



Q. Please explain the significance of this analysis for residential rate design.

A. The analysis above shows that the correlation between customers' average energy usage and maximum demand is greater than the correlation between a customers' highest month of usage and maximum demand. This in turn means that the current rate design (which is based on energy usage) more accurately accounts for a customer's maximum demand than the Company's proposal.

Q. Did you also analyze data for the G-1 class?

A. Yes. The results for the G-1 class indicate that the Company's approach (the highest month of usage) is only a slightly better indicator than average usage. However, this result is not sufficient to justify a dramatic departure from rate design goals and practices, for all of the other reasons discussed in our testimony.

Q. Has the Company demonstrated that its proposed tiered customer charge would represent an improvement over the current inclining block energy charge?

A. No. The Company proposes to eliminate the inclining block energy rate, asserting that "it provides an inaccurate price signal that increased usage results in increased cost...."[34] In addition, the Company claims that the inclining block rate has been ineffective in reducing energy usage.[35]

However, the Company's tiered customer charge is also based on a customer's energy usage, thereby failing to improve accuracy of the price signal. Further, the Company has not provided any evidence that its rate design would be more effective than the inclining block rate. In fact, the Company's proposed tiered customer charges are likely to be more controversial and confusing for average residential customers who will not understand the connection between demand and their highest month of usage, nor the reasons why the customer charge has a ratchet feature.

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[34] Prefiled Testimony of the Pricing Panel, page 50, line 15
[35] *Id.*, lines 11 -12.

Q. What do you conclude from your analysis?

A. Significant rate design changes should only be implemented if there is a significant improvement in customer equity or other rate design goals. We conclude that the Company's rate design does not represent an improvement in terms of customer equity. Our analysis demonstrates that a customer's highest month of usage is not a better indicator of a customer's demand on the system than average energy usage. Therefore there is no reason to implement the Company's drastic rate design changes.

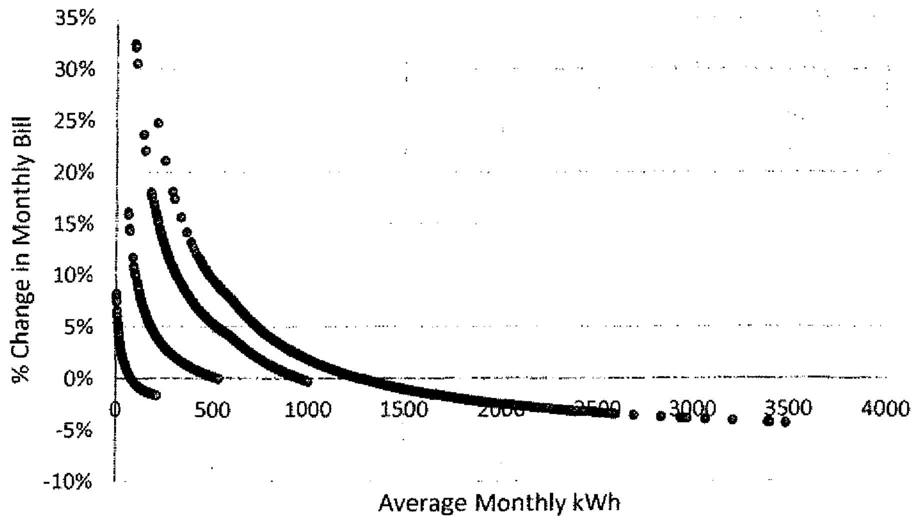
<u>Tiered Customer Charges Create New Rate Inequities</u>

Q. Have you analyzed the impact of the Company's proposed tiered customer charges on different types of customers?

A. Yes. Using the same data set as was used in the previous section, we estimated the percent change in each residential customer's monthly bill in the sample (including supply, transmission, and other charges.) We controlled for the increase in overall revenue requirement in order to isolate the impact of the rate design by itself. The graph below shows the change in each customer's monthly bill on the vertical axis, and the customer's average monthly usage (kWh) on the horizontal axis.

Because customers' monthly usage varies during the year, customers with the same average usage could have different levels of usage in their highest usage months, and would therefore fall into different customer charge tiers. For this reason, the points on the graph form four discrete lines that represent the effect of the different customer charge tiers; the left-most line includes customers in the lowest tier, and the right-most line includes customers in the highest tier.

Figure 4. Bill Impacts by Customer Average Usage Level



Q. What were the results of your analysis?

A. In addition to failing to improve customer equity, the Company's proposed tiered rate structure will have at least two detrimental impacts on customer equity:

1) Similar customers will experience large differences in their bills, depending upon whether their peak month of usage falls just above or below a tier boundary.

2) Under the Company's proposal, low-income customers would likely be hit hardest by any bill increases.

Q. Please explain why similar customers would experience dissimilar bills.

A. An artifact of the tiered customer charge structure is that it may produce widely differing impacts on customers due to an increase of 1 kWh in peak month usage, depending on whether the additional kilowatt-hour moves the customer across a boundary between two tiers.

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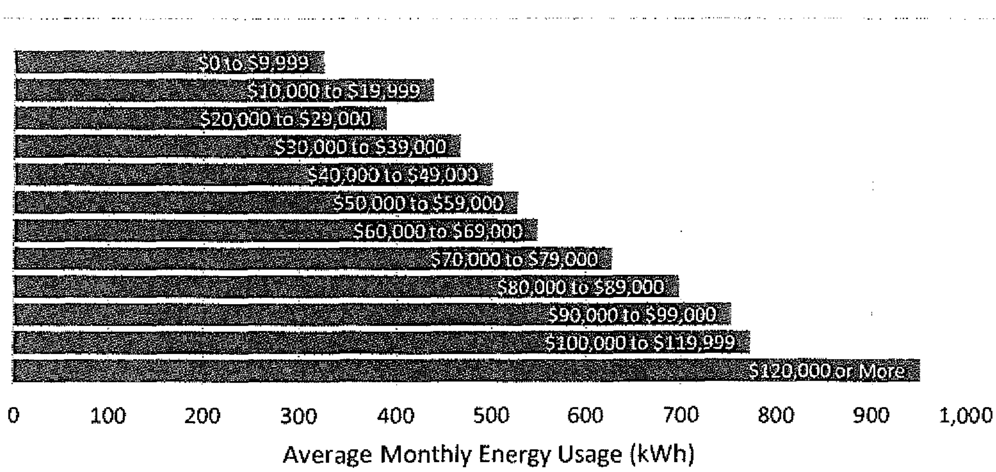
For example, consider two neighboring residential customers who have similar end-uses and load profiles, each with average energy use of 300 kWh per month. If Customer Smith consumed a maximum of 600kWh in one month, while Customer Jones consumed a maximum of 599 kWh, then the distribution portion of Smith's average monthly bill would be 33% higher than the distribution portion of Jones' average monthly bill. And this difference would persist for the next 12 months. Such significant variation violates the goal of fairness.

Q. Please explain why low-income customers would be hit hardest.

A. As illustrated by Figure 4, low- and moderate- usage customers are likely to bear a disproportionate amount of the bill increases, while customers consuming more than 1,200 kWh would experience reduced bills. While we do not have data on the individual customers that would sustain the highest bill increases, we know that in general, low income customers have the lowest electricity usage, according to the Energy Information Administration. The graph below presents the average electricity usage for each income group and shows that average usage increases tends to increase as household income rises.

Figure 5. Electricity Usage increases with Income in Massachusetts



Source: EIA's Residential Energy Consumption Survey, 2009, Massachusetts data

Because the Company's rate design proposal will concentrate bill increases on customers with low- or moderate usage, it is very likely that low-income customers will be more harmed by the tiered customer charges than high-income customers, due to low-income customers' propensity to be low-usage customers.

<u>The Company Has Failed to Demonstrate a Need for New Rate Designs</u>

Q. You noted that the Company claims that its rate design is intended to reflect the costs to serve each customer, "both those with and without DG." Is it necessary to create a new rate design at this time to address distributed generation customers?

A. No. While the Company claims that DG customers are not contributing their "fair share" of revenues, resulting in inequitable cost shifting,[36] it is not necessarily true that significant cost shifting is occurring or is likely to occur between DG and non-DG customers. As described in Section 4, when considering the costs created by customers, it is essential to consider "net" costs, which accounts for the benefits created by the customer as well as the costs. To ignore these benefits would skew the considerations of customer equity, and could discriminate against customers who provide those benefits.

[36] *Id,* page 31.

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Q. Please explain the Company's claim regarding cost-shifting between DG and non-DG customers.

A. The Company claims that net metering credits create a cross-subsidy because they result in lower revenue than expected, which must then be recovered from other customers.[37] Thus, even if the utility's costs are unchanged, the Company claims that the reduced sales from net metering may impact non-DG customers.

Q. Do lower bills for DG customers mean that customers with DG do not pay their fair share of distribution costs?

A. If one simply looks at a customer's bill before and after he or she installs DG, it appears as though the customer is not paying his or her fair share of costs because the bill is so much lower. However, this is an overly simplistic assessment of the impact of the distributed generation. An accurate assessment of that impact must consider the customer's contribution to system benefits as well as system costs. The system benefits of the distributed generation will certainly reduce, and possibly eliminate, the revenue-shifting that might be created by the reduced customer's bill.

Q. Should any such analysis consider new costs that DG customers might impose on the distribution system?

A. Yes. One should consider all of the benefits and all of the costs created by a customer group in order to fully understand the implications of cost-shifting by that group.

[37] Nat'l Grid Resp. to Information Req. EFCA 1-3, Feb. 12, 2016.

Q. Has the Company quantified the new distribution system costs imposed by DG?

A. No. The Company states that it "has not conducted its own study of the costs and benefits" associated with distributed generation,[38] and provides only one estimate of DG-related costs not currently recovered through interconnection fees: that of O&M for DG interconnection system modifications. The Company estimates that these costs currently total approximately $2.4 million per year,[39] but has not provided any basis for this estimate.

Q. Even though National Grid has not quantified the costs imposed by DG customers, has the Company indicated that these costs are likely to be significant?

A. No. To the contrary, the Company has acknowledged that in the short-term, any investments required to support DG will be "relatively low-cost."[40] Only as the quantity of DG on the system grows large does the Company anticipate that "potentially high cost" investments will be necessary.[41]

Q.

Q. Does the potential for future distribution costs or revenue-shifting among customers justify adjustments to the rate structure at this time?

A. No. First, we reiterate that no adjustments to rates should be made until both the costs and the benefits attributable to DG customers have been quantified and are better understood. Second, as the Company notes in its responses, current penetration levels do not threaten

[38] Nat'l Grid Resp. to Information Req. LI-1-10, Jan. 28, 2016.
[39] Nat'l Grid Resp. to Information Req. EFCA-1-11, Feb. 11, 2016.
[40] Nat'l Grid Resp. to Information Req. EFCA 1-9, Feb. 11, 2016.
[41] *Id.*

to impose significant costs on the distribution system. In fact, it is entirely possible that the benefits provided by DG customers outweigh any costs at present. Therefore it would be bad public policy to make such a dramatic modification to rate design for a cost that does not exist now, and might or might not exist sometime in the distant future.

Q. How do you recommend the Department address this question of revenue-shifting from DG in the future?

A. I recommend that the Department make it clear that if an electric utility argues for significant changes to ratemaking policy on the grounds that DG customers create unreasonable inequities and revenue-shifting, then such an argument must be justified with a comprehensive quantitative analysis of the likely impacts of DG on customers. This should be achieved with a long-term rate impact analysis that properly accounts for all the costs and benefits created by DG customers.

6. EFFICIENT PRICE SIGNALS AND TIERED CUSTOMER CHARGES

Q. Please summarize the importance of achieving efficient price signals through rate design.

A. As described in more detail in Section 4, efficiency is one of the Department's key rate design goals, and is of paramount importance in assessing the Company's rate design proposals in this case. Efficiency can best be achieved by sending efficient price signals to customers, which will enable them to modify their electricity consumption patterns through energy efficiency, demand response, distributed generation, storage, or other means. Efficient price signals, and efficient customer responses to those signals, will lead to the lowest cost mix of supply-side and demand-side resources over the long term, which will lead to the lowest electricity system costs for all customers.

Q. How would National Grid's proposed customers charges for R-1, R-2, E, and G-1 classes affect customer price signals?

A. The proposed increase in customer charges of up to 400 percent will send less efficient price signals by making more of the customers' bill essentially fixed and unavoidable for an entire year. This sends customers the signal that their usage of the system does not affect costs on the system, which is inefficient and contrary to the Department's rate structure goals and precedents, and inconsistent with Professor Bonbright's rate design principles described in Section 4. Inefficient price signals will generally result in higher long-term electricity costs for all customers.

Higher fixed charges are widely recognized as reducing incentives for energy efficiency and conservation. A recent report authored by Peter Kind notes that "the policy of adopting monthly fixed-charge increases has several flaws—principally that such increases would remove the price signals needed to encourage energy efficiency and efficient resource deployment."[42] This concern about increased fixed charges sending inefficient price signals is one of the main reasons why many commissions around the country have rejected significant increases to fixed charges in recent years.[43]

[42] Ceres, *Pathway to a 21st Century Electric Utility Model*, by Peter Kind, November 2015, page 6. Peter Kind is also the author of the influential 2013 EEI Report titled *Disruptive Challenges*, which encouraged utilities to seek fixed charges in rate cases. Accordingly, the fact that the author has backed off of his recommendation is notable. *See* Exhibit 6.

[43] Synapse Energy Economics, Inc. (2016), *Caught in a Fix*, prepared for Consumers Union, February 2016, pages 30-34.

Further, it is critical to recognize that a price signal can only be efficient if the target customer has the ability to respond in an efficient fashion. (In this way, the goals of simplicity and efficiency are closely linked, as described in Section 4.) However, it will be very difficult, if not impossible, for customers to understand, monitor, and respond the tiered customer charges, as described in the sections below.

Q. Are the price signals created by the Company's proposed tiered customer charges consistent with the Department's energy policy goals?

A. No. In addition to being inconsistent with the Department's rate structure goals, the inefficient price signals created by the Company's proposals are clearly inconsistent with the Department's long-standing policies and directives to promote energy efficiency and distributed energy resources. For example, in its order investigating the introduction of decoupling, the Department stated that

> demand resources represent the single most effective tool we have to mitigate the increases in and volatility of commodity gas and electricity prices. Demand resources allow participating host customers to significantly reduce their own energy bills. They also create downward pressure on wholesale gas and electric prices by lowering regional demand, thereby helping to lower energy bills throughout Massachusetts and the region.[44]

[44] Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources*, DPU 07-50-A, July 16, 2008, pages 3-4.

Q. But the Company offers comprehensive energy efficiency programs to encourage customers to adopt more efficient consumption patterns. Do these programs mean that price signals are not important?

A. No. Efficient customer price signals are a very important complement to the energy efficiency programs that National Grid provides to its customers. First, efficient price signals will make customers more interested in learning about and potentially participating in the Company's energy efficiency programs. Second, more efficient price signals should help the Company to either increase customer participation, reduce the financial incentives needed to promote customer participation, or both. Consequently, the energy efficiency programs will be more effective, less costly, or both. Third, efficient price signals can influence customer behavior with regard to other demand resources, beyond energy efficiency resources, such as distributed generation and storage.

7. CONTINUITY AND TIERED CUSTOMER CHARGES

Q. Does the Company's proposed tiered customer charge comport with the principle of continuity?

A. As described above, the Company has proposed to increase the customer charge for the majority of residential customers by between 125 percent and 400 percent from current rates. Similarly, the tiered customer charge would increase the customer charge by up to

200 percent for small business customers. Such a massive increase cannot be described as "gradual," and clearly violates the principle of continuity.[45]

Q. Are there compelling reasons for deviating from the principle of continuity in this case?

A. The Company has offered no compelling reason to impose such a drastic change in the rate structure. Instead, the Company has proposed a proxy for a demand charge that provides no improvement over the current rate structure, while threatening to create or exacerbate other inequities.

8. SIMPLICITY AND TIERED CUSTOMER CHARGES

Q. Does the Company's tiered customer charge proposal meet the goal of simplicity?

A. No. National Grid's proposal fails to meet the goal of simplicity and understandability. First, the rationale for the tiered customer charge – as a proxy for measuring a customer's maximum demand – will be difficult for customers to understand. Residential customers do not generally have a good understanding of demand, nor are they likely to understand what their monthly energy usage has to do with their maximum demand.

Second, customers do not have experience estimating what tier they are likely to fall into based on highest month of usage over a 12-month period, nor do they have the tools or experience to estimate whether their usage during the month is approaching the point

[45] Bonbright describes this principle as follows: "Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")" Bonbright (1961), *Principles of Public Utility Rates,* p. 291

where they might be knocked into a higher tier.[46] Simplicity should mean that customers are well positioned to adjust their behavior in order to reduce the magnitude of their bill. Currently residential customers understand that if they want to pay less, they should use less energy. Under the Company's proposal, this becomes much more difficult, as the customer does not know if his or her use right now is likely to impact their tier or not, and has no reasonably easy way to find out.

Q. Please explain why it will be very difficult for customers to adjust their behavior to respond to the tiered customer charges.

A. In order for customers to respond to the purported price signal of the tiered customer charge, they will need to know in which month they will experience their highest energy consumption for any one year. In the absence of advanced metering infrastructure, customers will only be able to look at historical monthly consumption levels to guess when the highest energy month will occur. Customers could easily guess incorrectly, as any one customer's highest energy month can change due to a variety of factors including: variable weather conditions, vacation schedules, changes to household members, major electricity end-use changes, building renovations, and more. If a customer guesses wrong, and undertakes initiatives to reduce energy consumption in the

[46] Not only do residential and small commercial customers not have the ability to easily monitor their usage during the month, the Company's metering system does not allow it to monitor these customers' usage and alert them when their usage is approaching a new tier. As noted in response to LI-2-12, "customers will not know, in real time, how close their actual monthly usage is to a tier boundary. Therefore, it will be important that customers are conscious of their energy consumption every single day, particularly during high use months, and work to keep consumption as low as possible in order to mitigate the chances of moving into a higher tier." Regarding the capability of the Company to notify customers of their usage, the Company states that it could develop the capability to notify customers "as they enter a month or series of months when their historical maximum usage was experienced," but "this notification to customers would not occur in real time, but would occur before customers enter a month or series of months in which they have historically experienced their maximum usage during the year. The Company has not calculated the cost to develop this capability."

month that is not the highest energy month, then those initiatives will not help the customer reduce his or her customer charge.

To make matters worse, customers will not know which month will be their highest energy month until after the month is over Under current metering and billing practices, customers are only informed of their monthly consumption levels until they receive their bills several weeks *after the end of the month.* Therefore, customers will not know for sure which month is the highest energy month until after the month has passed. By that point in time, there is no longer an opportunity to reduce their consumption for that month. In fact, some customers might not know which month will be their highest energy month until the end of the year.

Finally, if there are a few engaged and knowledgeable customers who are fortunate enough to guess the correct month for curtailing their electricity usage in any one year, then the following year the highest energy month might very well be a different month. This can hardly be described as an efficient price signal.

9. DEMAND RATCHETS FOR MEDIUM AND LARGE C&I CUSTOMERS

<u>Demand Ratchets Have Nearly the Same Effect as Increased Fixed Charges</u>

Q. What is the price signal that the Company wishes to send through the demand charge?

A. As noted previously, the Company states that the demand charge is intended to encourage customers "to shift load from high use, peak periods into off-peak periods" to improve utilization of the distribution system and "reduce the number of hours that the distribution system has to serve peak loads."[47]

Q. Will a demand ratchet provide an efficient price signal?

A. No. In order to provide an efficient price signal, rates should be set to encourage customers to use the system more efficiently. Unfortunately and shift load from peak to off-peak periods. The Company's proposal to implement a demand ratchet fails to accomplish this goal for several reasons. First, the demand ratchet fails to take into account the timing of a customer's demand and its coincidence with distribution system peaks. Second, the ratchet communicates to customers that a variable charge (the demand charge) is practically a fixed charge, since once the ratchet is set, it cannot be reduced for a year.

Q. Please explain why the failure to account for the timing of demand is important.

A. As shown previously, peaks on the distribution system tend to occur during summer afternoons. Since the demand ratchet is based on a customer's maximum demand on any day of the year,[48] it provides little incentive for customers to reduce demand when it matters most—during peak hours. Consider, for example, a customer that sets a maximum demand of 100 kW in the middle of a mild day in April. For the next 11

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[47] Prefiled Testimony of the Pricing Panel, page 30 of 89, lines 9-12.
[48] For G-2 customers, the demand ratchet is based on demand during any hour of any day, while for G-3 customers it is based on any peak hour of any day.

months, the customer would have little incentive to reduce his or her demand below 75 kW, even during hot August afternoons when the distribution system might be most stressed. In contrast, a demand charge based on maximum *monthly* demand[49] would encourage the customer to reduce his or her demand as low as possible for the month of August. Thus the current demand charge based on maximum monthly demand provides customers with a more efficient price signal than the Company's behavior.

Q. You likened the price signal sent by a demand ratchet to that of a fixed charge. What impact is such a price signal likely to have on customer behavior?

A. Ratchets act similarly to fixed charges in that, once set, they convey to the customer that their behavior will have no effect on their bill. For this reason, demand ratchets provide little incentive for customers to reduce their demand each month once they have set their highest demand, since demand reductions below 75 percent of the highest month's usage will not impact their bill. Because the demand ratchet is fixed for a year, it may also discourage investment in demand reduction technologies.

<u>Demand Ratchets Reduce Customer Incentives to Install Storage and Other Demand Resources</u>

Q. Will demand ratchets have negative impacts on any particular type of customer?

A. Yes. Demand ratchets tend to disproportionately increase bills for customers that have invested in demand resources, particularly energy storage technologies.

[49] An improvement on this would be to base the demand charge on maximum monthly demand during peak hours, for example from 11 am to 8 pm, or whatever hours are shown to be appropriate.

Q. What impact is this likely to have on customer behavior?

A. Ratchets provide no incentive for customers to reduce their demand each month once they have set their highest demand, since any demand under the highest month's usage will not impact their bill. This will also discourage investment in demand reduction technologies.

Consider, for example, a customer that typically exhibits an hourly load of 50 kWh. If this customer sets a peak demand of 100 kW in one month, the customer will have no incentive to reduce their load below 100 kW for the next 11 months of the year, other than for any small energy savings. This is likely to result in greater utilization of the system by customers, which will put greater strain on distribution system equipment and create a need for capacity upgrades sooner.

<u>Demand Ratchets Reduce Customer Incentives to Install Storage and Other Demand Resources</u>

Q. Will demand ratchets have negative impacts on any particular type of customer?

A. Yes. Demand ratchets tend to disproportionately increase bills for customers that have invested in demand resources, particularly energy storage technologies.

Q. What impact is the demand ratchet likely to have on customer investments in storage technologies?

A. The demand ratchet may significantly reduce incentives for customers to install storage technologies. While the impacts of the demand ratchet on a customer's bill will vary depending on the customer's overall usage and load profile, the ratchet penalizes customers whose monthly usage varies over the course of the year. For example, customers with solar PV and storage are likely to have low demands during the summer months, but higher demands during the winter months. This is due to the solar generation being used to reduce demand during daylight hours, and the storage system being able to charge during the day and reduce demand during the other hours.

By basing a demand charge on a customer's maximum annual demand rather than monthly demand, a demand ratchet would charge a customer with solar and storage technology based on their winter demand, and would not recognize that the customer has low demands during the summer when system capacity tends to be most stressed. This is likely to reduce customer investments in storage and reduce the use of existing storage systems.

Q. Why would the demand ratchet reduce the use of existing customer storage systems?

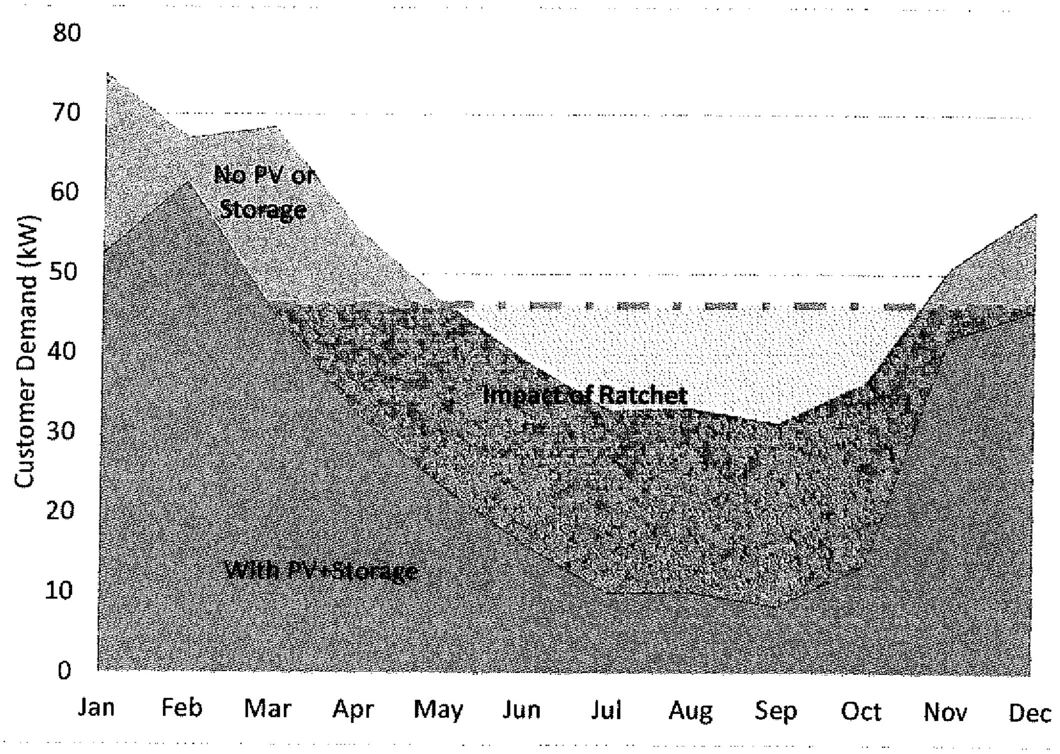
A. The demand ratchet will also decrease customer incentives to make use of their existing storage systems, since doing so will not help them avoid the demand ratchet most of the year. Battery performance degrades as the number of charge/discharge cycles increases. For this reason, battery owners have an incentive to use their batteries only when there is an economic benefit to doing so. If a customer knows that they cannot reduce their demand charge for the month due to the demand ratchet, they will be less likely to use their storage system to reduce demand on the grid.

Q. Can you provide an example?

Consider the example customer shown in the chart below, who has a solar array coupled with a storage system.

- The gray area shows the customer's maximum monthly demand without solar PV or storage. The customer's demand varies throughout the year but tends to be higher in the winter months, declining in the summer.
- The green area represents the customer's monthly demand with the addition of solar and storage.
- The dotted line represents the demand charge with the ratchet, which is based on 75 percent of a customer's maximum demand. Otherwise the demand charge is set equal to the customer's maximum monthly demand.
- The area below the dotted line and above the green area represents the increased kilowatt demand used to determine the customer's demand charge for the customer with solar PV and storage.

Figure 6. Example Impact of Demand Ratchet



Prior to the implementation of the demand ratchet, a customer's demand charge would be based on their maximum monthly demand. (For a customer without storage, the customer's monthly maximum demand is shown by the height of the gray area. For a customer with solar and storage, the monthly maximum is shown in green.) Once the demand ratchet is implemented, however, the customer's demand charge for the month is based on the greater of the customer's monthly demand or 75 percent of the customer's highest annual demand.

For the customer with storage, the customer's annual maximum demand is approximately 60 kw. Thus in each following month, the customer's demand charge will be based on demand of at least 45 kW (i.e., 75 percent of 60 kW). While this will generally result in higher demand charges for customers, it may also have negative impacts on system peak demands. Consider, for example, the month of July. Prior to the implementation of the demand ratchet, the customer would have reduced their demand in the month of July from 33 kW (shown in gray) to 10 kW (shown in green), through the use of their storage system. However, with the demand charge ratchet, the customer has no incentive to use their solar output and storage system to reduce demand, potentially leading to 23 kW more demand on the system than had the demand ratchet not been in place.[50]

Q. Have you performed any analysis to quantify the impacts on storage customers?

A. Yes. Based on load profile data provided by the Company, we examined the impact of the demand ratchet on six different G-2 customers with varying load profiles and maximum demands. To perform this analysis, we first grouped G-2 customers into six bins according to their maximum annual demand, and then from each bin selected a representative customer with complete annual load profile data and varying usage over the year.[51] We then estimated the impact of the demand ratchet on each customer based on (a) the customer's annual load profile, and (b) the customer's estimated load profile with the addition of a solar PV array and storage.

[50] The solar installation would continue to reduce the customer's demand during daylight hours, but the customer would require the battery to reduce demand in other hours. The customer's demand without the use of a battery could be up to 33 kW, depending on the hour during which such demand occurs.
[51] Data provided in Attachment EFCA 1-4-2.

Q. Please describe the results of your analysis.

A. We found that the demand ratchet's impacts[52] on customers without DG or storage tended to be relatively small, on the order of 1 to 2 percent increases in average bills. However, the bill increases on customers with solar and storage were generally much higher than on customers without storage,[53] with impacts exceeding five percent in three of the six cases, and reaching 21 percent in one case. More detailed results are provided in Exhibit 4.

Q. Does the Company's rate design represent better alignment with cost causation?

A. No. As discussed above, distribution system circuits tend to experience peak loads during summer afternoon hours. Increased demand during these hours will clearly lead to the need for additional distribution capacity, and therefore price signals should reflect the timing of demand. The Company's proposal does just the opposite – it discourages customers from investing in solar and storage technologies that will help to reduce demand on the distribution system during these hours.

Q. Please elaborate on the benefits of storage to the distribution system.

A. Storage not only allows customers to better manage their bills by reducing demand, but it can also reduce electric system costs for all customers by reducing congestion and stress on the grid. Further, storage can be used to help balance variable energy resources and

[52] We have excluded the impact of the Company's proposed rate adjustments from this analysis and focus only on the impact of the proposed demand ratchet structure.

[53] The only case in which the customer with storage fared slightly better than a customer without was in the case of a customer who experienced their highest annual demand in the summer daytime hours.

provide ancillary services and emergency response service in the wholesale markets.[54] Quite simply, storage offers a host of benefits to both the owner of the resource and the grid, and these benefits will become increasingly valuable as the quantity of renewable generation grows.

Despite these benefits, the Company's proposed rate design will discourage investments in storage. Further, the demand ratchet provides a perverse incentive to customers that have already invested in storage technologies, as it may encourage customers to not use their storage systems during summer months.

Q. Do you have any other concerns regarding the demand ratchet?

A. Yes. The demand ratchet is highly punitive for storage customers who experience a brief equipment failure, or who must temporarily conduct maintenance. Under such a scenario, a customer with storage could face an entire year of high demand charges due to a brief 15-minute spike in demand, despite the fact that a single customer's temporary demand spike would likely have little impact on the distribution system.

Q. Is the Company's rate design proposal consistent with Massachusetts' efforts to make the Commonwealth a national leader in energy storage?

A. No. National Grid's rate design proposals are inconsistent with the Baker Administration's efforts "to lead the way on clean energy, energy efficiency and the

[54] See, for example, International Renewable Energy Agency (2015) *Battery Storage for Renewables: Market Status and Technology Outlook,* available at http://www.irena.org/DocumentDownloads/Publications/IRENA_Battery_Storage_report_2015.pdf *and* The Brattle Group (2014) *The Value of Distributed Electricity Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments,* available at http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf

adoption of innovative technologies such as energy storage."[55] Further, the demand ratchet in particular is at odds with the Governor's $10 million Energy Storage Initiative, which seeks to analyze opportunities to support Commonwealth storage companies, as well as develop policy options to encourage energy storage deployment.[56]

Q. What do you conclude from your analysis?

A. We conclude that the demand ratchet fails to provide appropriate price signals, particularly for customers who have invested in distributed energy technologies such as storage. In addition, the Company's proposal would make investments in demand-reducing technologies increasingly risky, as a brief equipment failure could wipe out the technology's potential cost savings for an entire year.

Q. What do you recommend regarding the demand ratchet?

A. We recommend the Commission reject the Company's proposed demand ratchet and instead retain the current demand charge structure.

10. GENERAL SERVICE DEMAND CHARGE INCREASES

Q. Please explain why the Company is eliminating the energy charge for G-3 customers, a charge that is currently based on time-of-use.

A. The Company claims that eliminating the on-peak energy charge and recovering more costs through the demand charge will encourage customers to shift demand and flatten

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[55] Governor Charlie Baker's Statement on the *Governors' Accord for a New Energy Future*, available at http://www.governorsnewenergyfuture.org/news/.

[56] Massachusetts Executive Office of Energy and Environmental Affairs, *Baker-Polito Administration Announces $10 Million Energy Storage Initiative,* May 28, 2015, *available at http://www.mass.gov/eea/pr-2015/10-million-energy-storage-initiative-announced.html*

their load curves. The Company states that "Energy rates do not provide that incentive. Under energy rates, customers can move energy use from a period of high cost to another with lower costs and create new peaks in the lower cost period."[57] The Company further argues that distribution "must serve the peak load whenever it occurs."

Q. Will the Company's proposal improve incentives for customers to flatten their load curves?

A. No. The Company currently only assesses a demand charge during peak hours, and is not proposing to assess a demand charge during off-peak hours. Simply eliminating the on-peak energy charge and replacing it with a higher on-peak demand charge provides no incentive to reduce load during off-peak hours, potentially also leading to the creation of new peaks during off-peak hours. In short, the Company's stated rationale is inconsistent with its proposed rate structure for G-3 customers.

Q. Is the Company's proposal to eliminate the energy charge and increase the G-3 demand charge likely to increase customer efficiency incentives?

A. No. A price of $0.00 per kWh sends a very strong price signal that reducing electricity usage is not of value. Further, the Company is not only proposing to eliminate the energy charge, but is also proposing to implement a demand ratchet. As discussed above, the demand ratchet significantly reduces the incentive for customers to reduce demand in non-peak months, as the demand ratchet effectively converts the demand charge to a fixed charge for 11 months out of the year. This effect will only be heightened through

[57] Nat'l Grid Resp. to Information Req. DPU-21-4, Feb. 27, 2016.

the removal of the energy charge, as reductions in energy usage will not impact the customer's distribution portion of their bill in all but one hour. Thus incentives for energy efficiency, storage, or other technologies will be reduced by the Company's rate design.

Q: What do you recommend regarding the Company's proposal to eliminate the energy charge?

A: We recommend that the Department reject the Company's proposed G-3 rate design.

11. GRID MODERNIZATION GOALS

Q. Please describe the Department's recent activities regarding grid modernization.

A. In 2012 the Department opened a docket to investigate grid modernization in Massachusetts.[58] The Department's purpose of this investigation was

> to examine our policies and ensure that electric distribution companies adopt grid modernization technologies and practices to enhance the reliability of electricity service, reduce costs of operating the electric grid, mitigate price increases and volatility for customers, and empower customers to adopt new electricity technologies and better manage their use of electricity.[59]

In June 2014, the Department issued an order in that docket requiring each Massachusetts electric distribution company to submit a grid modernization plan.[60]

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[58] Synapse Energy Economics, along with Raab Associates, assisted the Department in the Grid Modernization stakeholder process in this docket.

[59] Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid*, DPU 12-76-A, page 1.

[60] Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid*, DPU 12-76-B.

In August 2015 the Company submitted its Grid Modernization Plan to the Department. In that plan the Company claimed that grid modernization can "empower customers to improve their efficient use of energy, enable two-way power flow and increase integration of distributed generation."[61]

In March 2016 the Department issued a procedural order opening up the investigation into the Company's Grid Modernization Plan.[62]

Q. Has the Department recently issued other orders related to grid modernization?

A. Yes. As an outcome of the grid modernization investigation, the Department opened an investigation into time varying rates. In that docket the Department established a policy framework for implementing time-varying rates, which requires that electric distribution companies offer basic service customers: (1) a default time of use rate with a critical peak price component; and (2) an option to opt out of the default rate and choose a flat rate with a peak time rebate component.[63]

Q. Are the Company's rate design proposals in this docket consistent with the Department's grid modernization goals?

A. No. As described above, the rate design proposals for R-1, R-2, G-1, G-2, and G-3 will not send efficient price signals to customers, will discourage customers from adopting energy efficiency and distributed generation, and will therefore undermine the

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[61] National Grid, *Grid Modernization Plan*, Testimony of Peter Zschokke, August 19, 2015, page 7.

[62] Massachusetts Department of Public Utilities, *Notice of Filing, Public Hearing, and Procedural Conference*, DPU 15-120, March 8, 2016.

[63] Massachusetts Department of Public Utilities, *Order Adopting Policy Framework For Time Varying Rates*, DPU 14-04-C, November 5, 2014, page 2.

Department's grid modernization goals. In fact, the Company's rate design proposals are inconsistent with its own grid modernization goals (cited above), for the same reasons.

Q. Are the Company's proposed tiered customer charges consistent with the Department's time-varying rates policy framework?

A. No. They directly conflict with the Department's time-varying rates policy framework. If the Company were to established tiered customer charges as a result of this docket, and then implement time-varying rates for basic service in the near- to mid-term future, then the rate designs for R-1, R-2 and G-1 classes would certainly violate the Department's goal of simplicity. Few of these customers, if any, would have the interest, the information, or the technologies to optimize their electricity consumption in response to both basic service time-varying rates and tiered customer charges.

The combined impact of tiered customer charges and time-varying rates would also violate the Department's goal of continuity. These two changes have the potential to result in significant rate increases that would be unjustified by corresponding increases in costs.

It would be much more appropriate for the Company to maintain its current rate designs, and investigate alternative rate designs at a later date in the context of grid modernization and time-varying rate decisions and goals. This would allow for a more holistic approach to grid modernization, time-varying rates, and rate design, and would help ensure that new rate designs meet all of the Department key goals.

12. RECOMMENDATIONS

Q. Please summarize your recommendations.

A. We offer the following recommendations:

- The Department should reject the Company's proposal for tiered customer charges for R-1, R-2, and G-1 classes. Further, the Department should not increase the current customer charges for these customers by any more than the percentage increases that are applied to the energy charges for these classes to attain the class revenue requirements allowed by the Department in this docket.
- The Department should reject the Company's proposal to introduce a demand ratchet for G-2 and G-3 customers.
- The Department should reject the Company's proposal to increase the demand related charges for G-3 customers.
- The Department should refrain from entertaining proposals to significantly modify current rate designs absent resolution of the Department's prior orders regarding time-varying rates.
- The Department should articulate that if the Company wishes to make significant modifications to rate design practices on the grounds of customer equity and cost-shifting from distributed generation customers, it must first conduct a thorough quantitative analysis of any cost shifting, which should include all relevant costs

Q. Does this conclude your direct testimony?

A. Yes, it does.

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EXHIBIT 1

Tim Woolf, Vice President

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 2011 – present.

Provides expert consulting on the economic, regulatory, consumer, environmental, and public policy implications of the electricity and gas industries. The primary focus of work includes technical and economic analyses, electric power system planning, climate change strategies, energy efficiency programs and policies, renewable resources and related policies, power plant performance and economics, air quality, and many related aspects of consumer and environmental protection.

Massachusetts Department of Public Utilities, Boston, MA. *Commissioner*, 2007 – 2011.

Oversaw a significant expansion of clean energy policies as a consequence of the Massachusetts Green Communities Act, including an aggressive expansion of ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power. Oversaw six rate case proceedings for Massachusetts electric and gas companies. Played an influential role in the development of price responsive demand proposals for the New England wholesale energy market. Served as President of the New England Conference of Public Utility Commissioners from 2009-2010. Served as board member on the Energy Facilities Siting Board from 2007-2010. Served as co-chair of the Steering Committee for the Northeast Energy Efficiency Partnership's Regional Evaluation, Measurement and Verification Forum.

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 1997 – 2007.

Tellus Institute, Boston, MA. *Senior Scientist, Manager of Electricity Program*, 1992 – 1997.

Association for the Conservation of Energy, London, England. *Research Director*, 1991 – 1992.

Massachusetts Department of Public Utilities, Boston, MA. *Staff Economist*, 1989 – 1990.

Massachusetts Office of Energy Resources, Boston, MA. *Policy Analyst*, 1987 – 1989.

Energy Systems Research Group, Boston, MA. *Research Associate*, 1983 – 1987.

Union of Concerned Scientists, Cambridge, MA. *Energy Analyst*, 1982-1983.

EDUCATION

Boston University, Boston, MA
Master of Business Administration, 1993

London School of Economics, London, England
Diploma, Economics, 1991

Tufts University, Medford, MA
Bachelor of Science in Mechanical Engineering, 1982

Tufts University, Medford, MA
Bachelor of Arts in English, 1982

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Ackerman, F., B. Biewald, D. White, T. Woolf, W. Moomaw. 1999. "Grandfathering and Coal Plant Emissions: the Cost of Cleaning Up the Clean Air Act." *Energy Policy* 27 (15): 929–940.

Biewald, B., D. White, T. Woolf. 1999. "Follow the Money: A Method for Tracking Electricity for Environmental Disclosure." *The Electricity Journal* 12 (4): 55–60.

Woolf, T., B. Biewald. 1998. "Efficiency, Renewables and Gas: Restructuring As if Climate Mattered." *The Electricity Journal* 11 (1): 64–72.

Woolf, T., J. Michals. 1996. "Flexible Pricing and PBR: Making Rate Discounts Fair for Core Customers." *Public Utilities Fortnightly*, July 1996.

Woolf, T., J. Michals. 1995. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry." *The Electricity Journal* 8 (8): 64–72.

Woolf, T. 1994. "Retail Competition in the Electricity Industry: Lessons from the United Kingdom." *The Electricity Journal* 7 (5): 56–63.

Woolf, T. 1994. "A Dialogue About the Industry's Future." *The Electricity Journal* 7 (5).

Woolf, T., E. D. Lutz. 1993. "Energy Efficiency in Britain: Creating Profitable Alternatives." *Utilities Policy* 3 (3): 233–242.

Woolf, T. 1993. "It is Time to Account for the Environmental Costs of Energy Resources." *Energy and Environment* 4 (1): 1–29.

Woolf, T. 1992. "Developing Integrated Resource Planning Policies in the European Community." *Review of European Community & International Environmental Law* 1 (2) 118–125.

PRESENTATIONS

Lowry, M. N., T. Woolf. 2015. "Performance-Based Regulation in a High Distributed Energy Resources Future." Webinar on January 27, 2016.

Woolf, T. 2014. "The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening." Presentation at the ACEEE Summer Study, August 21, 2014.

Woolf, T. 2013. "Recommendations for Reforming Energy Efficiency Cost-Effectiveness Screening in the United States." Presentation at the National Association of Regulatory Commissioners Annual Meeting, November 18, 2013.

Woolf, T., B. Biewald, and J. Migden-Ostrander. 2013. "NARUC Risk Workshop for Regulators." Presentation at the Mid-Atlantic Conference of Regulatory Utility Commissioners, June 2013.

Woolf, T. 2013. "Energy Efficiency Screening: Accounting for 'Other Program Impacts' & Environmental Compliance Costs." Presentation for Regulatory Assistance Project Webinar, March 2013.

Woolf, T. 2013. "Energy Efficiency: Rates, Bills, Participants, Screening, and More." Presentation at Connecticut Energy Efficiency Workshop, March 2013.

Woolf T. 2013. "Best Practices in Energy Efficiency Program Screening." Presentation for SEE Action Webinar, March 2013.

Woolf, T. 2013. "Energy Efficiency Screening: Application of the TRC Test." Presentation for Energy Advocates Webinar, January 2013.

Woolf, T. 2012. "Best Practices in Energy Efficiency Program Screening." Presentation for American Council for an Energy-Efficient Economy Webinar, December 2012.

Woolf, T. 2012. "In Pursuit of All Cost-Effective Energy Efficiency." Presentation at Sierra Club Boot Camp, October 2012.

Woolf, T. 2012. "Best Practices in Energy Efficiency Program Screening." Presentation at NARUC Summer Meetings – Energy Efficiency Cost-Effectiveness Breakfast, July 2012.

Woolf, T. 2011. "Energy Efficiency Cost-Effectiveness Tests." Presentation at the Northeast Energy Efficiency Partnerships Annual Meeting, October 2011.

Woolf, T. 2011. "Why Consumer Advocates Should Support Decoupling." Presentation at the 2011 ACEEE National Conference on Energy Efficiency as a Resource, September 2011.

Woolf, T. 2011. "A Regulator's Perspective on Energy Efficiency." Presentation at the Efficiency Maine Symposium *In Pursuit of Maine's Least-Cost Energy*, September 2011.

Woolf, T. 2010. "Bill Impacts of Energy Efficiency Programs: The Importance of Analyzing and Managing Rate and Bill Impacts." Presentation at the Energy in the Northeast Conference, Law Seminar International, September 2010.

Woolf, T. 2010. "Bill Impacts of Energy Efficiency Programs: The Implications of Bill Impacts in Developing Policies to Motivate Utilities to Implement Energy Efficiency." Presentation to the State Energy Efficiency Action Network, Utility Motivation Work Group, November 2010.

Woolf, T. 2010. "Bill Impacts of Energy Efficiency Programs." Presentation to the Energy Resources and Environment Committee at the NARUC Winter Meetings, February 2010.

Woolf, T. 2009. "Price-Responsive Demand in the New England Wholesale Energy Market: Description of NECPUC's Limited Supply-Side Proposal." Presentation at the NEPOOL Markets Committee Meeting, November 2009.

Woolf, T. 2009. "Demand Response in the New England Wholesale Energy Market: How Much Should We Pay for Demand Resources?" Presentation at the New England Electricity Restructuring Roundtable, October 2009.

Woolf, T. 2008. "Promoting Demand Resources in Massachusetts: A Regulator's Perspective." Presentation at the Energy Bar Association, Northeast Chapter Meeting, June 2008.

Woolf, T. 2008. "Turbo-Charging Energy Efficiency in Massachusetts: A DPU Perspective." Presentation at the New England Electricity Restructuring Roundtable, April 2008.

Woolf T. 2002. "A Renewable Portfolio Standard for New Brunswick." Presentation to the New Brunswick Market Design Committee, January 10, 2002.

Woolf, T. 2001. "Potential for Wind and Renewable Resource Development in the Midwest." Presentation at WINDPOWER 2001 in Washington DC, June 7, 2001.

Woolf T. 1999. "Challenges Faced by Clean Generation Resources Under Electricity Restructuring." Presentation at the Symposium on the Changing Electric System in Florida and What it Means for the Environment in Tallahassee, FL, November 1999.

Woolf, T. 2000. "Generation Information Systems to Support Renewable Portfolio Standards, Generation Performance Standards and Environmental Disclosure." Presentation at the Massachusetts Restructuring Roundtable on behalf of the Union of Concerned Scientists, March 2000.

Woolf, T. 1998. "New England Tracking System Project: An Electricity Tracking System to Support a Wide Range of Restructuring-Related Policies." Presentation at the Ninth Annual Energy Services Conference and Exposition in Orlando, FL, December 1998.

Woolf, T. 2000. "Comments of the Citizens Action Coalition of Indiana." Presentation at Workshop on Alternatives to Traditional Generation Resources, June 2000.

Woolf, T. 1996. "Overview of IRP and Introduction to Electricity Industry Restructuring." Training session provided to the staff of the Delaware Public Service Commission, April 1996.

Woolf, T. 1995. "Competition and Regulation in the UK Electric Industry." Presentation at the Illinois Commerce Commission's workshop on Restructuring the Electric Industry, August 1995.

Woolf, T. 1995. "Competition and Regulation in the UK Electric Industry." Presentation at the British Columbia Utilities Commission Electricity Market Review, February 1995.

TESTIMONY

Maine Public Utilities Commission (Docket No. 2015-00175): Direct testimony on Efficiency Maine Trust's petition for approval of the Triennial Plan for Fiscal Years 2017-2019. On behalf of the Natural Resources Council of Maine and the Conservation Law Foundation. February 17, 2016.

Nevada Public Utilities Commission (Docket Nos. 15-07041 and 15-07042): Direct testimony on NV Energy's application for approval of a cost of service study and net metering tariffs. On behalf of The Alliance for Solar Choice. October 27, 2015.

New Jersey Board of Public Utilities (Docket No. ER14030250): Direct testimony on Rockland Electric Company's petition for investments in advanced metering infrastructure. On behalf of the New Jersey Division of Rate Counsel. September 4, 2015.

Utah Public Service Commission (Docket No. 14-035-114): Direct, rebuttal, and surrebuttal testimony on the benefit-cost framework for net energy metering. On behalf of Utah Clean Energy, the Alliance for Solar Choice, and Sierra Club. July 30, 2015, September 9, 2015, and September 29, 2015.

Nova Scotia Utility and Review Board (Matter No. M06733): Direct testimony on EfficiencyOne's 2016-2018 demand-side management plan. On behalf of the Nova Scotia Utility and Review Board. June 2, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony on the topic of Kansas City Power and Light's rate design proposal. On behalf of Sierra Club. April 16, 2015 and June 5, 2015.

Missouri Public Service Commission (File No. EO-2015-0055): Rebuttal and surrebuttal testimony on the topic of Ameren Missouri's 2016-2018 Energy Efficiency Plan. On behalf of Sierra Club. March 20, 2015 and April 27, 2015.

Florida Public Service Commission (Dockets No. 130199-EI et al.): Direct testimony on the topic of setting goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems. On behalf of the Sierra Club. May 19, 2014.

Massachusetts Department of Public Utilities (Docket No. DPU 14-__): Testimony regarding the cost of compliance with the Global Warming Solution Act. On behalf of the Massachusetts Department of Energy Resources and the Department of Environmental Protection. May 16, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

Maine Public Utilities Commission (Docket No. 2013-168): Direct and surrebuttal testimony regarding policy issues raised by Central Maine Power's 2014 Alternative Rate Plan, including recovery of capital costs, a Revenue Index Mechanism proposal, and decoupling. On behalf of the Maine Public Advocate Office. December 12, 2013 and March 21, 2014.

Colorado Public Utilities Commission (Docket No. 13A-0686EG): Answer and surrebuttal testimony regarding Public Service Company of Colorado's proposed energy savings goals. On behalf of the Sierra Club. October 16, 2013 and January 21, 2014.

Kentucky Public Service Commission (Case No. 2012-00578): Direct testimony regarding Kentucky Power Company's economic analysis of the Mitchell Generating Station purchase. On behalf of the Sierra Club. April 1, 2013.

Nova Scotia Utility and Review Board (Matter No. M04819): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2013 – 2015. On behalf of the Counsel to Nova Scotia Utility and Review Board. May 22, 2012.

Missouri Office of Public Counsel (Docket No. EO-2011-0271): Rebuttal testimony regarding IRP rule compliance. On behalf of the Missouri Office of the Public Counsel. October 28, 2011.

Nova Scotia Utility and Review Board (Matter No. M03669): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2012. On behalf of the Counsel to Nova Scotia Utility and Review Board. April 8, 2011.

Rhode Island Public Utilities Commission (Docket No. 3790): Direct testimony regarding National Grid's Gas Energy Efficiency Programs. On behalf of the Division of Public Utilities and Carriers. April 2, 2007.

North Carolina Utilities Commission (Docket E-100, Sub 110): Filed comments with Anna Sommer regarding the Potential for Energy Efficiency Resources to Meet the Demand for Electricity in North Carolina. Synapse Energy Economics on behalf of the Southern Alliance for Clean Energy. February 2007.

Rhode Island Public Utilities Commission (Docket No. 3765): Direct and Surrebuttal testimony regarding National Grid's Renewable Energy Standard Procurement Plan. On behalf of the Division of Public Utilities and Carriers. January 17, 2007 and February 20, 2007.

Minnesota Public Utilities Commission (Docket Nos. CN-05-619 and TR-05-1275): Direct testimony regarding the potential for energy efficiency as an alternative to the proposed Big Stone II coal project. On behalf of the Minnesota Center for Environmental Advocacy, Fresh Energy, Izaak Walton League of America, Wind on the Wires and the Union of Concerned Scientists. November 29, 2006.

Rhode Island Public Utilities Commission (Docket No. 3779): Oral testimony regarding the settlement of Narragansett Electric Company's 2007 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 24, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-04002 & 06-04005): Direct testimony regarding Nevada Power Company's and Sierra Pacific Power Company's Renewable Portfolio Standard Annual Report. On behalf of the Nevada Bureau of Consumer Protection. October 26, 2006

Nevada Public Utilities Commission (Docket No. 06-06051): Direct testimony regarding Nevada Power Company's Demand-Side Management Plan in the 2006 Integrated Resource Plan. On behalf of the Nevada Bureau of Consumer Protection. September 13, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-03038 & 06-04018): Direct testimony regarding the Nevada Power Company's and Sierra Pacific Power Company's Demand-Side Management Plans. On behalf of the Nevada Bureau of Consumer Protection. June 20, 2006.

Nevada Public Utilities Commission (Docket No. 05-10021): Direct testimony regarding the Sierra Pacific Power Company's Gas Demand-Side Management Plan. On behalf of the Nevada Bureau of Consumer Protection. February 22, 2006.

South Dakota Public Utilities Commission (Docket No. EL04-016): Direct testimony regarding the avoided costs of the Java Wind Project. On behalf of the South Dakota Public Utilities Commission Staff. February 18, 2005.

Rhode Island Public Utilities Commission (Docket No. 3635): Oral testimony regarding the settlement of Narragansett Electric Company's 2005 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 29, 2004.

British Columbia Utilities Commission. Direct testimony regarding the Power Smart programs contained in BC Hydro's Revenue Requirement Application 2004/05 and 2005/06. On behalf of the Sierra Club of Canada, BC Chapter. April 20, 2004.

Maryland Public Utilities Commission (Case No. 8973): Oral testimony regarding proposals for the PJM Generation Attributes Tracking System. On behalf of the Maryland Office of People's Counsel. December 3, 2003.

Rhode Island Public Utilities Commission (Docket No. 3463): Oral testimony regarding the settlement of Narragansett Electric Company's 2004 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 21, 2003.

California Public Utilities Commission (Rulemaking 01-10-024): Direct testimony regarding the market price benchmark for the California renewable portfolio standard. On behalf of the Union of Concerned Scientists. April 1, 2003.

Québec Régie de l'énergie (Docket R-3473-01): Direct testimony with Philp Raphals regarding Hydro-Québec's Energy Efficiency Plan: 2003-2006. On behalf of Regroupment national des Conseils régionaux de l'environnement du Québec. February 5, 2003.

Connecticut Department of Public Utility Control (Docket No. 01-10-10): Direct testimony regarding the United Illuminating Company's service quality performance standards in their performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. April 2, 2002.

Nevada Public Utilities Commission (Docket No. 01-7016): Direct testimony regarding the Nevada Power Company's Demand-Side Management Plan. On behalf of the Bureau of Consumer Protection, Office of the Attorney General. September 26, 2001.

United States Department of Energy (Docket Number-EE-RM-500): Comments with Bruce Biewald, Daniel Allen, David White, and Lucy Johnston of Synapse Energy Economics regarding the Department of

Energy's proposed rules for efficiency standards for central air conditioners and heat pumps. On behalf of the Appliance Standards Awareness Project. December 2000.

US Department of Energy (Docket EE-RM-500): Oral testimony at a public hearing on marginal price assumptions for assessing new appliance efficiency standards. On behalf of the Appliance Standards Awareness Project. November 2000.

Connecticut Department of Public Utility Control (Docket No. 99-09-03 Phase II): Direct testimony regarding Connecticut Natural Gas Company's proposed performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. September 25, 2000.

Mississippi Public Service Commission (Docket No. 96-UA-389): Oral testimony regarding generation pricing and performance-based ratemaking. On behalf of the Mississippi Attorney General. February 16, 2000.

Delaware Public Service Commission (Docket No. 99-328): Direct testimony regarding maintaining electric system reliability. On behalf of Delaware Public Service Commission Staff. February 2, 2000.

Delaware Public Service Commission (Docket No. 99-328): Filed expert report ("Investigation into the July 1999 Outages and General Service Reliability of Delmarva Power & Light Company," jointly authored with J. Duncan Glover and Alexander Kusko). Synapse Energy Economics and Exponent Failure Analysis Associates on behalf the Delaware Public Service Commission Staff. February 1, 2000.

New Hampshire Public Service Commission (Docket No. 99-099 Phase II): Oral testimony regarding standard offer services. On behalf of the Campaign for Ratepayers Rights. January 14, 2000.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Rebuttal testimony regarding codes of conduct. On behalf of the West Virginia Consumer Advocate Division. July 15, 1999.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Direct testimony regarding codes of conduct and other measures to protect consumers in a restructured electricity industry. On behalf of the West Virginia Consumer Advocate Division. June 15, 1999.

Public Service Commission of West Virginia (Case No. 98-0452-E-GI): Filed expert report ("Measures to Ensure Fair Competition and Protect Consumers in a Restructured Electricity Industry in West Virginia," jointly authored with Jean Ann Ramey and Theo MacGregor) in the matter of the General Investigation to determine whether West Virginia should adopt a plan for open access to the electric power supply market and for the development of a deregulation plan. Synapse Energy Economics and MacGregor Energy Consultancy on behalf of the West Virginia Consumer Advocate Division. June 1999.

Massachusetts Department of Telecommunications and Energy (DPU/DTE 97-111): Direct testimony regarding Commonwealth Electric Company's energy efficiency plan, and the role of municipal aggregators in delivering demand-side management programs. On behalf of Cape and Islands Self-Reliance Corporation. January 1998.

Delaware Public Service Commission (DPSC 97-58): Direct testimony regarding Delmarva Power and Light's request to merge with Atlantic City Electric. On behalf of Delaware Public Service Commission Staff. May 1997.

Delaware Public Service Commission (DPSC 95-172): Oral testimony regarding Delmarva's integrated resource plan and DSM programs. On behalf of the Delaware Public Service Commission Staff. May 1996.

Colorado Public Utilities Commission (5A-531EG): Direct testimony regarding the impact of proposed merger on DSM, renewable resources and low-income DSM. On behalf of the Colorado Office of Energy Conservation. April 1996.

Colorado Public Utilities Commission (3I-199EG): Direct testimony regarding the impacts of increased competition on DSM, and recommendations for how to provide utilities with incentives to implement DSM. On behalf of the Colorado Office of Energy Conservation. June 1995.

Colorado Public Utilities Commission (5R-071E): Oral testimony on the Commission's integrated resource planning rules. On behalf of the Colorado Office of Energy Conservation. July 1995.

Colorado Public Utilities Commission (3I-098E): Direct testimony on the Public Service Company of Colorado's DSM programs and integrated resource plans. On behalf of the Colorado Office of Energy Conservation. April 1994.

Delaware Public Service Commission (Docket No. 96-83): Filed comments regarding the Investigation of Restructuring the Electricity Industry in Delaware (Tellus Institute Study No. 96-99). On behalf of the Staff of the Delaware Public Service Commission. November 1996.

Colorado Public Utilities Commission (Docket No. 96Q-313E): Filed comments in response to the Questionnaire on Electricity Industry Restructuring (Tellus Institute Study No. 96-130-A3). On behalf of the Colorado Governor's Office of Energy Conservation. October 1996.

State of Vermont Public Service Board (Docket No. 5854): Filed expert report (Tellus Institute Study No. 95-308) regarding the Investigation into the Restructuring of the Electric Utility Industry in Vermont. On behalf of the Vermont Department of Public Service. March 1996.

Pennsylvania Public Utility Commission (Docket No. I-00940032): Filed comments (Tellus Institute Study No. 95-260) regarding an Investigation into Electric Power Competition. On behalf of The Pennsylvania Office of Consumer Advocate. November 1995.

New Jersey Board of Public Utilities (Docket No. EX94120585Y): Initial and reply comments ("Achieving Efficiency and Equity in the Electricity Industry Through Unbundling and Customer Choice," Tellus Institute Study No. 95-029-A3) regarding an investigation into the future structure of the electric power industry. On behalf of the New Jersey Division of Ratepayer Advocate. September 1995.

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EXHIBIT 2

Synapse
Energy Economics, Inc.

Melissa Whited, Senior Associate

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mwhited@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge MA. *Senior Associate, 2015 – present, Associate*, 2012 – 2015

Conduct research, author reports, and assist in preparation of expert testimony. Consult on issues related to energy efficiency, demand response, renewable resources, water use and conservation, regional economic impacts, cost-benefit analysis, integrated resource planning, utility ratemaking, and market power.

University of Wisconsin - Madison, Department of Agricultural and Applied Economics, Madison, WI. *Teaching Assistant – Environmental Economics*, 2011 – 2012

Developed teaching materials and led discussions on cost-benefit analysis, carbon taxes and cap-and-trade programs, management of renewable and non-renewable resources, and other topics.

Public Service Commission of Wisconsin, Water Division, Madison, WI. *Program and Policy Analyst - Intern*, Summer 2009

Researched water conservation programs nationwide to develop a proposal for Wisconsin's state conservation program. Developed spreadsheet model to calculate avoided costs of water conservation in terms of energy savings and avoided emissions.

Synapse Energy Economics, Cambridge, MA. *Communications Manager*, 2005 – 2008

Developed technical proposals for state and federal agencies, environmental and public interest groups, and businesses. Edited reports on energy efficiency, integrated resource planning, greenhouse gas regulations, renewable resources, and other topics.

National Council for International Visitors, Washington, DC. *Program Associate*, 2003 – 2005

Managed print media, provided membership services, and assisted in preparing core grant proposal and annual and quarterly reports. Researched and produced community economic impact statements.

International Gender and Trade Network, Washington, DC. *Research Intern*, Summer 2003

Researched implications of water privatization in developing countries.

EDUCATION

University of Wisconsin, Madison, WI
Master of Arts in Agricultural and Applied Economics, 2012. Certificate in Energy Analysis and Policy.

University of Wisconsin, Madison, WI
Master of Science in Environment and Resources, 2010

Southwestern University, Georgetown, TX
Bachelor of Arts in International Studies, 2003. *Magna cum laude.*

ADDITIONAL SKILLS

Analytical abilities:

- Econometric Modeling – Linear and nonlinear modeling including time-series, panel data, logit, probit, and discrete choice regression analysis
- Nonmarket Valuation Methods for Environmental Goods – Hedonic valuation, travel cost method, and contingent valuation
- Cost-Benefit Analysis
- Input-Output Modeling for Regional Economic Analysis

Software:

- MATLAB (Econometric analysis)
- IMPLAN (IMpact analysis for PLANning) Economic Model
- R Statistical Package (OLS and Time-Series Regression Analysis)
- STATA Statistical Package
- STELLA System Dynamics Modeling Software

FELLOWSHIPS AND AWARDS

- Winner, M. Jarvin Emerson Student Paper Competition, Journal of Regional Analysis and Policy, 2010
- Fellowship, National Science Foundation Integrative Graduate Education and Research Traineeship (IGERT), University of Wisconsin – Madison, 2009
- Nelson Distinguished Fellowship, University of Wisconsin – Madison, 2008

PUBLICATIONS

Whited, M., T. Woolf, J. Daniel. 2016. *Caught in a Fix: The Problem with Fixed Charges for Electricity.* Synapse Energy Economics for Consumers Union.

Lowry, M. N., T. Woolf, M. Whited, M. Makos. 2016. *Performance-Based Regulation in a High Distributed Energy Resources Future.* Pacific Economics Group Research and Synapse Energy Economics for Lawrence Berkley National Laboratory.

Woolf, T., M. Whited, A. Napoleon. 2015-2016. *Comments and Reply Comments in the New York Public Service Commission Case 14-M-0101: Reforming the Energy Vision.* Comments related to Staff's (a) a benefit-costs analysis framework white paper, (b) ratemaking and utility business models white paper, and (c) Distributed System Implementation Plan guide. Prepared by Synapse Energy Economics on behalf of Natural Resources Defense Council and Pace Energy and Climate Center.

Luckow, P., B. Fagan, S. Fields, M. Whited. 2015. *Technical and Institutional Barriers to the Expansion of Wind and Solar Energy.* Synapse Energy Economics for Citizens' Climate Lobby.

Wilson, R., M. Whited, S. Jackson, B. Biewald, E. A. Stanton. 2015. *Best Practices in Planning for Clean Power Plan Compliance.* Synapse Energy Economics for the National Association of State Utility Consumer Advocates.

Whited, M., T. Woolf, A. Napoleon. 2015. *Utility Performance Incentive Mechanisms: A Handbook for Regulators.* Synapse Energy Economics for the Western Interstate Energy Board.

Stanton, E. A., S. Jackson, B. Biewald, M. Whited. 2014. *Final Report: Implications of EPA's Proposed "Clean Power Plan."* Synapse Energy Economics for the National Association of State Utility Consumer Advocates.

Peterson, P., S. Fields, M. Whited. 2014. *Balancing Market Opportunities in the West: How participation in an expanded balancing market could save customers hundreds of millions of dollars.* Synapse Energy Economics for the Western Grid Group.

Woolf, T., M. Whited, E. Malone, T. Vitolo, R. Hornby. 2014. *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits.* Synapse Energy Economics for the Advanced Energy Economy Institute.

Peterson, P., M. Whited, S. Fields. 2014. *Synapse Comments on FAST Proposals in ERCOT.* Synapse Energy Economics for Sierra Club.

Hornby, R., N. Brockway, M. Whited, S. Fields. 2014. *Time-Varying Rates in the District of Columbia.* Synapse Energy Economics for the Office of the People's Counsel for the District of Columbia, submitted to Public Service Commission of the District of Columbia in Formal Case No. 1114.

Peterson, P., M. Whited, S. Fields. 2014. *Demonstrating Resource Adequacy in ERCOT: Revisiting the ERCOT Capacity, Demand and Reserves Forecasts.* Synapse Energy Economics for Sierra Club – Lone Star Chapter.

Stanton, E. A., M. Whited, F. Ackerman. 2014. *Estimating the Cost of Saved Energy in Utility Efficiency Programs.* Synapse Energy Economics for the U.S Environmental Protection Agency.

Ackerman, F., M. Whited, P. Knight. 2014. "Would banning atrazine benefit farmers?" *International Journal of Occupational and Environmental Health* 20 (1): 61–70.

Ackerman, F., M. Whited, P. Knight. 2013. *Atrazine: Consider the Alternatives.* Synapse Energy Economics for Natural Resources Defense Council (NRDC).

Whited, M., F. Ackerman, S. Jackson. 2013. *Water Constraints on Energy Production: Altering our Current Collision Course.* Synapse Energy Economics for Civil Society Institute.

Whited, M. 2013. *Water Constraints on Energy Production: Altering our Current Collision Course – Policy Brief.* Synapse Energy Economics for Civil Society Institute.

Hurley, D., P. Peterson, M. Whited. 2013. *Demand Response as a Power System Resource: Program Designs, Performance, and Lessons Learned in the United States.* Synapse Energy Economics for Regulatory Assistance Project.

Whited, M., D. White, S. Jackson, P. Knight, E.A. Stanton. 2013. *Declining Markets for Montana Coal.* Synapse Energy Economics for Northern Plains Resource Council.

Woolf, T., M. Whited, T. Vitolo, K. Takahashi, D. White. 2012. *Indian Point Energy Center Replacement Analysis: A Plan for Replacing the Nuclear Plant with Clean, Sustainable, Energy Resources.* Synapse Energy Economics for National Resources Defense Council and Riverkeeper.

Whited, M., K. Charipar, G. Brown. *Demand Response Potential in Wisconsin.* Nelson Institute for Environmental Studies, Energy Analysis & Policy Capstone for the Wisconsin Public Service Commission.

Whited, M. 2010. "Economic Impacts of Irrigation Water Transfers in Uvalde County, Texas." *Journal of Regional Analysis and Policy* 40 (2): 160–170.

Grabow, M., M. Hahn and M. Whited. 2010. *Valuing Bicycling's Economic and Health Impacts in Wisconsin.* Nelson Institute for Environmental Studies, Center for Sustainability and the Global Environment (SAGE) for State Representative Spencer Black.

Whited, M., D. Bernhardt, R. Deitchman, C. Fuchsteiner, M. Kirby, M. Krueger, S. Locke, M. Mcmillen, H. Moussavi, T. Robinson, E. Schmitz, Z. Schuster, R. Smail, E. Stone, S. Van Egeren, H. Yoshida, Z. Zopp. 2009. *Implementing the Great Lakes Compact: Wisconsin Conservation and Efficiency Measures Report.* Department of Urban and Regional Planning, University of Wisconsin-Madison, Extension Report 2009-01.

Whited, M. 2009. *2009 Wisconsin Water Fact Sheet.* Public Service Commission of Wisconsin.

Whited, M. 2003. *Gender, Water, and Trade.* International Gender and Trade Network Washington, DC.

TESTIMONY

Federal Energy Regulatory Commission (Docket No. EC13-93-000): Affidavit regarding potential market power resulting from the acquisition of Ameren generation by Dynegy. On behalf of Sierra Club. August 16, 2013.

Wisconsin Senate Committee on Clean Energy: Joint testimony with M. Grabow regarding the importance of clean transportation to Wisconsin's public health and economy. February 2010.

TESTIMONY ASSISTANCE

Nevada Public Utilities Commission (Docket Nos. 15-07041 and 15-07042): Direct testimony on NV Energy's application for approval of a cost of service study and net metering tariffs. On behalf of The Alliance for Solar Choice. October 27, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony on the topic of Kansas City Power and Light's rate design proposal. On behalf of Sierra Club. April 16, 2015 and June 5, 2015.

Wisconsin Public Service Commission (Docket No. 05-UR-107): Direct and surrebuttal testimony of Rick Hornby regarding Wisconsin Electric Power Company rate case. On behalf of The Alliance for Solar Choice. August 28, 2014 and September 22, 2014.

Maine Public Utilities Commission (Docket No. 2013-00519): Direct testimony of Richard Hornby and Martin R. Cohen on GridSolar's smart grid coordinator petition. On behalf of the Maine Office of the Public Advocate. August 28, 2014.

Maine Public Utilities Commission (Docket No. 2013-00168): Direct and surrebuttal testimony of Tim Woolf regarding Central Maine Power's request for an alternative rate plan. December 12, 2013 and March 21, 2014.

Massachusetts Department of Public Utilities (Docket No. 14-04): Comments of Massachusetts Department of Energy Resources on investigation into time varying rates. On behalf of the Massachusetts Department of Energy Resources. March 10, 2014.

State of Nevada, Public Utilities Commission of Nevada (Docket No. 13-07021): Direct testimony of Frank Ackerman regarding the proposed merger of NV Energy, Inc. and MidAmerican Energy Holdings Company. On behalf of the Sierra Club. October 24, 2013.

PRESENTATIONS

Whited, M., T. Woolf. 2016. "Caught in a Fix: The Problem with Fixed Charges for Electricity." Webinar presentation sponsored by Consumers Union, February 2016.

Whited, M. 2015. "Performance Incentive Mechanisms." Presentation to the National Governors Association, Learning Lab on New Utility Business Models & the Electricity Market Structures of the Future.

Whited, M. 2015. "Rate Design: Options for Addressing NEM Impacts." Presentation to the Utah Net Energy Metering Workgroup, Workshop 4, July 8, 2015.

Whited, M. 2015. "Performance Incentive Mechanisms." Presentation to the e21 Initiative, May 2015.

Whited, M., F. Ackerman. 2013. "Water Constraints on Energy Production: Altering our Current Collision Course." Webinar presentation sponsored by Civil Society Institute, September 2013.

Whited, M., G. Brown, K. Charipar. 2011. "Electricity Demand Response Programs and Potential in Wisconsin." Presentation to the Wisconsin Public Service Commission, April 2011.

Whited, M. 2010. "Economic Impact of Irrigation Water Transfers in Uvalde County, Texas." Presentation at the Mid-Continent Regional Science Association's 41st Annual Conference/IMPLAN National User's 8th Biennial Conference in St. Louis, MO, June 2010.

Whited, M., M. Grabow, M. Hahn.2009. "Valuing Bicycling's Economic and Health Impacts in Wisconsin." Presentation before the Governor's Coordinating Council on Bicycling, December 2009.

Whited, M., D. Sheard. 2009. "Water Conservation Initiatives in Wisconsin." Presentation before the Waukesha County Water Conservation Coalition Municipal Water Conservation Subgroup, July 2009.

Resume dated January 2016

EXHIBIT 3

of principles, these chapters are mere essays on the nature of the more controversial, largely unresolved, problems rather than attempts at systematic development. All of them have one theme in common: the thesis that the most formidable obstacles to further progress in the theory of public utility rates are those raised by conflicting goals of rate-making policy.

CRITERIA OF A DESIRABLE RATE STRUCTURE

Throughout this study we have stressed the point that, while the ultimate purpose of rate theory is that of suggesting feasible *measures* of reasonable rates and rate relationships, an intelligent choice of these measures depends primarily on the accepted *objectives* of rate-making policy and secondarily on the need to minimize undesirable side effects of rates otherwise best designed to attain these objectives. No rational discussion, for example, of the relative merits of "cost of service" and "value of service" as measures of proper rates or rate relationships is possible without reference to the question what desirable results the rate maker hopes to secure, and what undesirable results he hopes to minimize, by a choice between or mixture of the two standards of measurement. Not only this: the very *meaning* to be attached to ambiguous, proposed measures such as those of "cost" or "value"—an ambiguity not completely removed by the addition of familiar adjuncts, such as "out-of-pocket" costs, or "marginal costs," or "average costs"—must be determined in the light of the purposes to be served by the public utility rates as instruments of economic policy. This is a commonplace; but it is a commonplace which, so far from being taken for granted, needs repeated emphasis.

What then, are the good attributes to be sought and the bad attributes to be avoided or minimized in the development of a sound rate structure? Many different answers have been suggested in the technical literature and in the reported opinions by courts and commissions; and a number of writers have summarized their answers in the form of a list of desirable attributes of a rate structure, comparable to the "canons of taxation" found in the treatises on public finance. The list that follows is fairly typical, although I have derived it from a variety of sources instead of relying on any

one presentation. The sequence of the eight items is not meant to suggest any order of relative importance.

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company:
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

Lists of this nature are useful in reminding the rate maker of considerations that might otherwise escape his attention, and also useful in suggesting one important reason why problems of practical rate design do not readily yield to "scientific" principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities (how, for example, does one define "undue discrimination"?), their overlapping character, and their failure to offer any rules of priority in the event of a conflict. For such a base, we must start with a simpler and more fundamental classification of rate-making objectives.

THREE PRIMARY CRITERIA

General principles of public utility rates and rate differentials are necessarily based on simplified assumptions both as to the objectives of rate-making policy and as to the factual circumstances un-

EXHIBIT 4

Exhibit 4
Impacts of Demand Ratchets on Six Customers with Storage

Based on load profile data provided by the Company, we examined the impact of the demand ratchet on six different G-2 customers with varying load profiles and maximum demands. To perform this analysis, we first grouped G-2 customers into six bins according to their maximum annual demand, and then from each bin selected a representative customer with complete annual load profile data and varying usage over the year.[63] We then estimated the impact of the demand ratchet on each customer based on (a) the customer's annual load profile, and (b) the customer's estimated load profile with the addition of a solar PV array and a storage system.

We found that the demand ratchet's impacts[64] on customers without DG or storage tended to be relatively small, on the order of 1 to 2 percent increases in average bills. However, the impacts on customers with solar and storage were generally much higher than on customers without storage, with impacts exceeding five percent in three of the six cases, and reaching 21 percent in one case. If the demand ratchet were implemented as proposed and storage customers continued to use their storage systems as they previously had, four of the six customers would experience total bill increases of more than 9 percent. ~~If, however, the customers reprogram their storage systems in an effort to reduce the bill increases from the ratchet, the bill impacts would decrease but still generally exceed those of non-storage customers and would remain above five percent for three of the six storage customers.~~ [KS23]

[63] Data provided in Attachment EFCA 1-4-2. The selection of customers was not intended to represent extreme cases; rather we attempted to select load profiles that were fairly typical.

[64] We have excluded the impact of the Company's proposed rate adjustments from this analysis and focus only on the impact of the proposed demand ratchet structure.

The graph below illustrates the impacts of the demand ratchet on the six example customers analyzed. For each of the six customer categories, the striped gray bars on the left indicate the bill impacts on customers without storage, while the green bars indicate the impacts on customers with storage. If a customer could optimize the behavior of their battery to reduce the demand ratchet impact, this is shown by the light green portion of the bar.

Figure 7. Impact of the Demand Ratchet on Six Customers

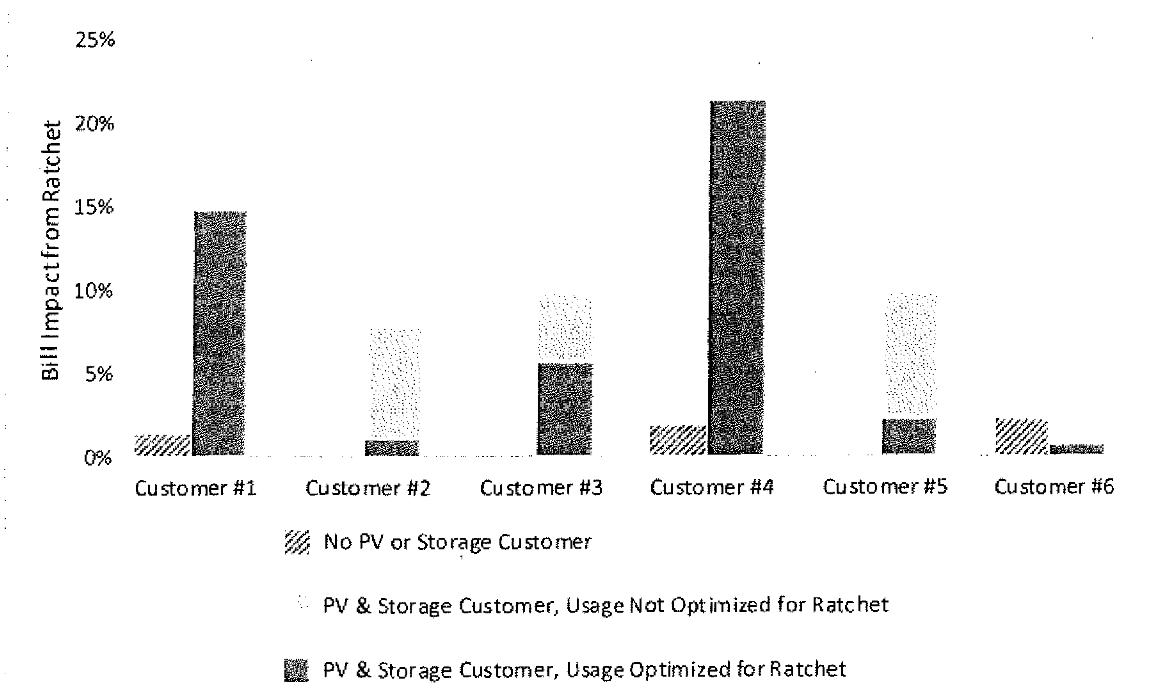

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EXHIBIT 5

SolarCity

Grid Engineering

A Pathway to the Distributed Grid

Evaluating the economics of distributed energy resources and outlining a pathway to capturing their potential value

White Paper

Executive Summary

Designing the electric grid for the 21st century is one of today's most important and exciting societal challenges. Regulators, legislators, utilities, and private industry are evaluating ways to both modernize the aging grid and decarbonize our electricity supply, while also enabling customer choice, increasing resiliency and reliability, and improving public safety, all at an affordable cost.

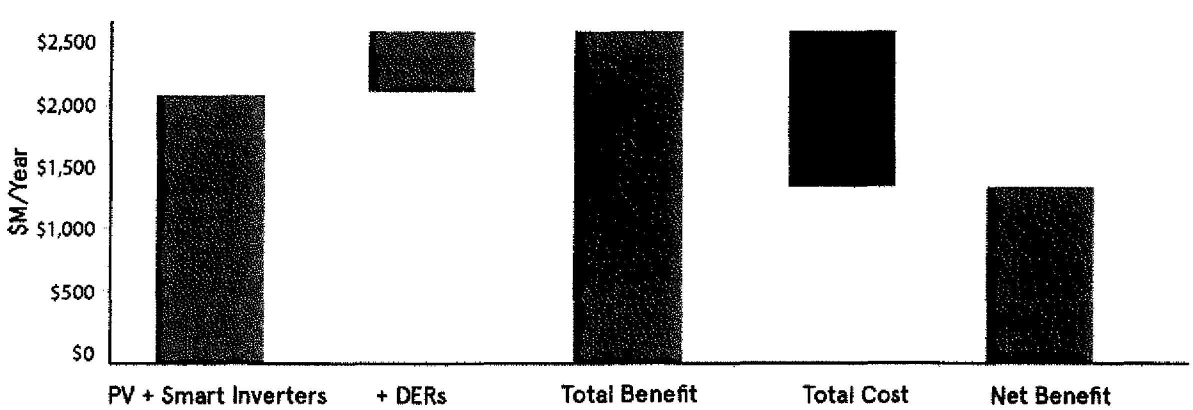
However, modernizing an aging grid will require significant investments over and above those seen in any recent period – potentially exceeding $1.5 trillion in the U.S. between 2010-2030.[1] Given the large sums of ratepayer funds at stake and the long-term impact of today's decisions, it is imperative that such investment is deployed wisely, cost-effectively, and in ways that leverage the best technology and take advantage of customers' desire to manage their own energy.

In this report, we explore the capability of distributed energy resources (DERs) to maximize ratepayer benefits while modernizing the grid. First, we quantify the net societal benefits from proactively leveraging DERs deployed in the next five years, which we calculate to be worth over $1.4 billion a year in California alone by 2020. Then, we apply this methodology to the most recently available Investor Owned Utility (IOU) General Rate Case (GRC) filing – Pacific Gas and Electric's 2017 GRC – in order to evaluate whether DERs can cost effectively replace real-world planned distribution capacity projects. Finally, we evaluate the impediments to capturing these benefits in practice. These structural impediments undermine the deployment of optimal solutions and pose economic risk to consumers, who ultimately bear the burden of an expensive grid. Accordingly, we suggest several ways to overcome these impediments by improving the prevailing utility regulatory and planning models.

Distributed Energy Resources Offer a Better Alternative

This report presents an economic analysis of building and operating a 21st century power grid – a grid that harnesses the full potential of distributed energy resources such as rooftop solar, smart inverters, energy storage, energy efficiency, and controllable loads. We find that an electric grid leveraging DERs offers an economically better alternative to the centralized design of today. DERs bring greater total economic benefits at lower cost, enable more affordability and consumer choice, and improve flexibility in grid planning and operations, all while facilitating the de-carbonization of our electricity supply.

Over $1.4 Billion per Year in Net Societal Benefits from DERs by 2020



February 2016

To evaluate the potential benefits, we build on existing industry methodologies to quantify the net societal benefits of DERs. Specifically, we borrow the *Net Societal Costs/Benefits* framework from the Electric Power Research Institute (EPRI),[2] incorporating commonly recognized benefit and cost categories, while also proposing methodologies for several hard-to-quantify benefit categories that are often excluded from traditional analyses. Next, we incorporate costs related to the deployment and utilization of DERs, including integration costs at the bulk system and distribution levels, DER equipment costs, and utility program management costs. Using this structure, we quantify Net Societal Benefits of more than $1.4 billion a year by 2020 for California alone from DER assets deployed in the 2016-2020 timeframe, as depicted in the previous figure.

In addition to evaluating net societal benefits at the system level, we consider the benefits of DER solutions for specific distribution projects in order to evaluate whether DERs can actually defer or replace planned utility investments in practice. Specifically, we apply the relevant set of cost and benefit categories to the actual distribution investment plans from California's most recently available GRC filing, which is PG&E's 2017 General Rate Case Phase I filing. This real-world case study assesses a commonly voiced critique of utilizing DERs in place of traditional utility infrastructure investments: that not all avoided cost categories are applicable for every distribution project, or that DERs only provide a subset of their potential benefits in any specific project. Therefore, we consider only a subset of utility-applicable avoided cost categories when assessing the set of distribution infrastructure projects in PG&E's 2017 GRC filing; we also utilize PG&E's own avoided cost values rather than our own assumptions. Even using PG&E's conservative assumptions on this subset of benefits, we quantify a net benefit for DER solutions used to replace the distribution capacity investments in PG&E's 2017 GRC.

Utility Regulatory Incentives Must Change in Order to Capture DER Benefits

While our analysis shows net societal benefits from DERs, both at the societal and distribution project levels, under the prevailing utility regulatory model DER benefits cannot be fully captured. Instead, utilities have a fundamental financial incentive of "build more to profit more", which conflicts with the public interest of building and maintaining an affordable grid. Under today's regulatory paradigm, utilities see a negative financial impact from utilizing resources for distribution services that they do not own – which includes the vast majority of distributed energy resources – even if those assets would deliver higher benefits at lower cost to ratepayers. This financial incentive model is a vestige of how utilities have always been regulated, a model originally constructed to encourage the expansion of electricity access. However, in this age of customers managing their energy via DERs, this regulatory model is outdated. This report offers a pathway to removing this structural obstacle, calling for a regulatory model that neutralizes the conflict of incentives facing utilities. While separating the role of grid planning and sourcing from the role of grid asset owner – such as through the creation of an independent distribution system operator (IDSO) – would achieve this objective, some states may choose not to implement an IDSO model at this time. In these instances, this paper proposes the creation of a new utility sourcing model, which we call *Infrastructure-as-a-Service*, that allows utility shareholders to derive income, or a rate of return, from competitively sourced third-party services. This updated model would help reduce the financial disincentive that currently biases utility decision-making against DERs, encouraging utilities to deploy grid investments that maximize ratepayer benefits regardless of their ownership.

Grid Planning Must be Modernized in Order to Capture DER Benefits

A second structural impediment to realizing DER benefits is the current grid planning approach, which biases grid design toward traditional infrastructure rather than distributed alternatives, even if distributed solutions better meet grid needs. Combined with the "build more to profit more" financial incentive challenge, current grid planning can encourage 'gold-plating', or overinvestment, in grid infrastructure. Furthermore, outdated planning approaches rely on static assumptions about DER capabilities and focus primarily on mitigating potential integration challenges rather than proactively harnessing these flexible assets. This report offers a pathway to modernizing grid planning, calling for the utilization of an *Integrated Distribution Planning* approach that encourages incorporating DERs into every aspect of planning, rather than merely accommodating DER interconnection. Additionally, transparency into grid needs and planned investments is fundamental to realizing benefits. As such, this report recommends a data transparency approach that invites broad stakeholder engagement and increases industry competition in providing grid solutions.

Key Takeaways

1. Distributed energy resources offer *net economic benefits to society* worth more than $1.4 billion per year in California alone by 2020, including benefits related to voltage and power quality, conservation voltage reduction, grid reliability and resiliency, equipment life extension, and reduced energy prices.

2. To realize these benefits, the *utility regulatory incentive model* must change to take advantage of customer choices to manage their own energy. Utility incentives should promote best-fit, least-cost investment decisions regardless of service supplier – eliminating the current bias toward utility-owned investments.
3. Utility planning approaches must also be modernized to capture these benefits. Utilization of an *integrated distribution planning* framework will unlock the economic promise of distributed energy resources, while widely sharing utility grid data in standard data formats will invite broader stakeholder engagement and competition.

Recommendations and Next Steps

Our ultimate goal is to help provide concrete evidence and recommendations needed by regulators, legislatures, utilities, DER providers, and industry stakeholders to transition to a cleaner, more affordable and resilient grid. While the details of implementing these recommendations would vary from state to state, we see the following as promising steps forward for all industry stakeholders in modernizing our grid:

1. Future regulatory proceedings and policy venues related to capturing the benefits of DERs should *incorporate the expanded benefit and cost categories* identified in this paper.
2. Regulators should look for near-term opportunities to *modernize the utility incentive model*, either for all utility earnings or at a minimum for demonstration projects, to eliminate the bias toward utility-owned investments.
3. Regulators should require utilities to *modernize their planning processes* to integrate and leverage distributed energy resources, utilizing the integrated distribution planning process identified in this paper.
4. Regulators should require utilities to *categorize all planned distribution investments* in terms of the underlying grid need. Utilities should make data available electronically to industry, ideally in a machine-readable format.

Call for Input

We offer this paper as an effort to support the utilization of grid modernization to maximize ratepayer benefits. The cost/benefit analysis we develop here is an effort meant to expand the industry's ability to quantify the holistic contribution that DERs offer to the grid and its customers, extending the familiar cost/benefit framework beyond PV-only analyses and into full smart inverter and DER portfolios. Furthermore, we recognize that important regulatory proceedings – such as the CPUC Distribution Resource Plans (DRP) and CPUC Integrated Distributed Energy Resources (IDER) – will play an important role in giving stakeholders the tools to calculate the value of DERs, and offer this paper a as resource in those efforts.

No single report could adequately address all the issues – engineering, economic, regulatory – that naturally arise during such a transformative time in the industry. By compiling the major issues in one place, we attempt to advance the discussion and suggest that this paper includes a "table of contents" of critical topics for regulators and industry stakeholders to consider when evaluating the full potential of distributed energy resources.

There are many details of this paper that can be refined, including utilizing more complete data sets to inform the cost/benefit analysis. We welcome ongoing dialogues with utilities and other stakeholders to improve the assumptions or calculations herein, including sharing data and revising methodologies to arrive at more representative figures. In fact, most of the authors of this paper are former utility engineers, economists, technologists, and policy analysts, and would value the opportunity to collaborate. We welcome a constructive dialogue, and can be reached at gridx@solarcity.com.

Acknowledgements

We would like to thank the following industry stakeholders who were willing to provide their valuable feedback on the content of this paper. While we incorporated their input to every extent possible, we, the authors, are solely responsible for the information presented and the conclusions drawn in the report.

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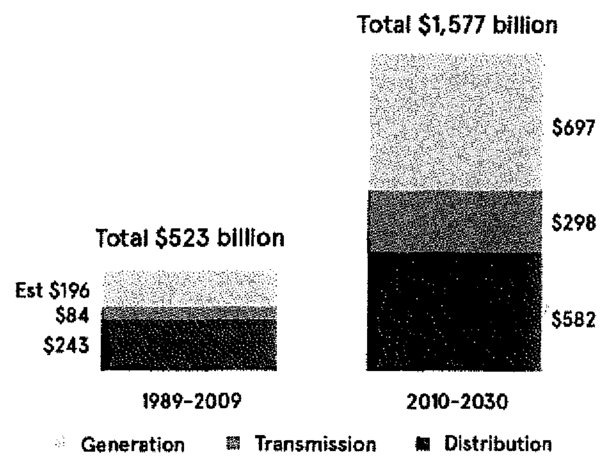
I. Introduction

Grid Investments are Increasing

Grid infrastructure planners are responsible for some of the most significant infrastructure investments in the United States. As of 2011, U.S. utilities had almost half a trillion dollars of undepreciated transmission, distribution and generation assets on their balance sheets, growing at a rate of 6 to 8% per year.[3] As depicted in the adjacent figure, the Edison Electric Institute forecasts that another $879 billion dollars in distribution and transmission investments alone will occur in the twenty year period of 2010 through 2030 – about $44 billion dollars per year – significantly larger than investments seen in the previous 20 year period.[4] Grid investments have a significant and increasing impact on the total electricity costs faced by U.S. consumers.

U.S. Grid Investments



In light of this huge level of grid investment occurring over the next few decades, an imperative exists to ensure that these investments are deployed to maximize ratepayer benefits. There has been relatively little focus to date on how to effectively focus and reduce these infrastructure costs, particularly in the areas of transmission and distribution planning, despite the fact that they often make up half of the average residential customer's bill. This level of investment calls for a reexamination of the technological solutions available to meet the grid's needs and an overhaul of the planning process that deploys these solutions. States like California and New York have begun this process, primarily spurred by a focus on how distribution planning and operations may evolve in a future with high penetration of distributed resources.[5] While these nascent discussions and rulemakings are positive first steps, the planning framework for grid modernization must change considerably to avoid costing ratepayers billions in unnecessary, underutilized investments.

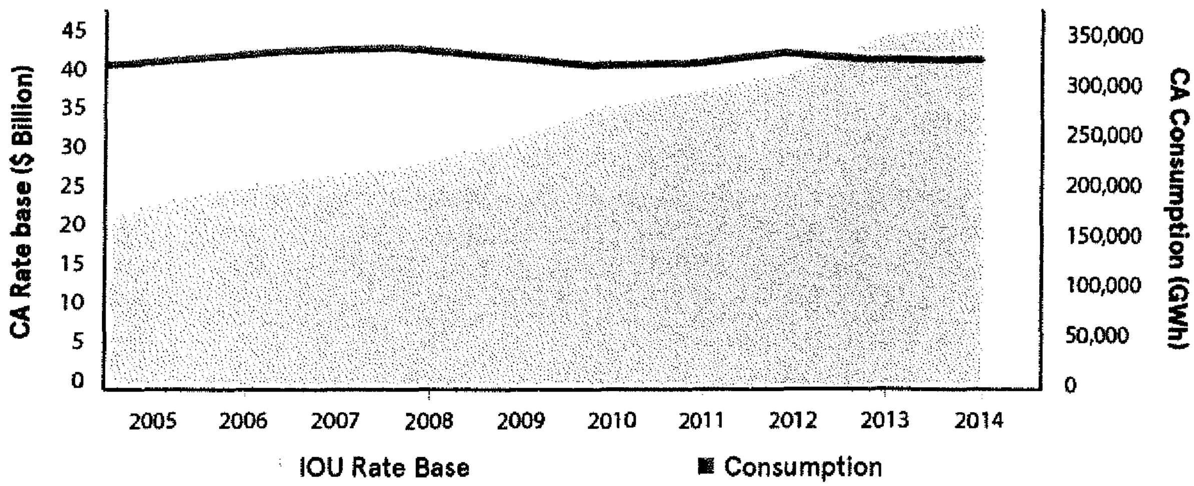
Current Utility Regulatory Model Incents a *Build More to Profit More* Approach

The current utility regulatory model, which was designed around a monopoly utility managing all aspects of grid design and operation, is outdated and unsuited for today's reality of consumers installing DERs that can benefit the grid. Therefore, industry fundamentals need to be reexamined, and the utility incentive model is a key place to start.

Electric utilities are generally regulated under a "cost plus" model, which compensates utilities with an authorized rate of return on prudent capital investments made to provide electricity services. While this model makes sense when faced with a regulated firm operating in a natural monopoly, it is well known to result in a number of economic inefficiencies, as perhaps best analyzed by Jean Tirole in his Nobel Prize winning work on market power and regulation.[6]

One fundamental problem resulting from the "cost plus" utility regulatory model is that utilities are generally discouraged from utilizing infrastructure resources that are not owned by the utility, even if competitive alternatives could deliver improved levels of service at a lower cost to ratepayers. Beyond regulatory oversight, this model contains no inherent downward economic pressure on the size of the utility rate base, or the cumulative amount of assets upon which the utility earns a rate of return. As such, utility rate bases have consistently and steadily grown over time. For example, the following chart depicts the size and recent growth of the electricity rate base for California investor-owned utilities, which continues to significantly grow even in the presence of flat electricity consumption. In short, the fundamental incentive utilities have to build more utility-owned infrastructure in order to profit more conflicts with the public interest as the grid becomes more customer-centric and distributed.

Trends in Rate Base for California Investor-Owned Utilities[7,8]



Traditional Grid Planning Focuses on Traditional Assets

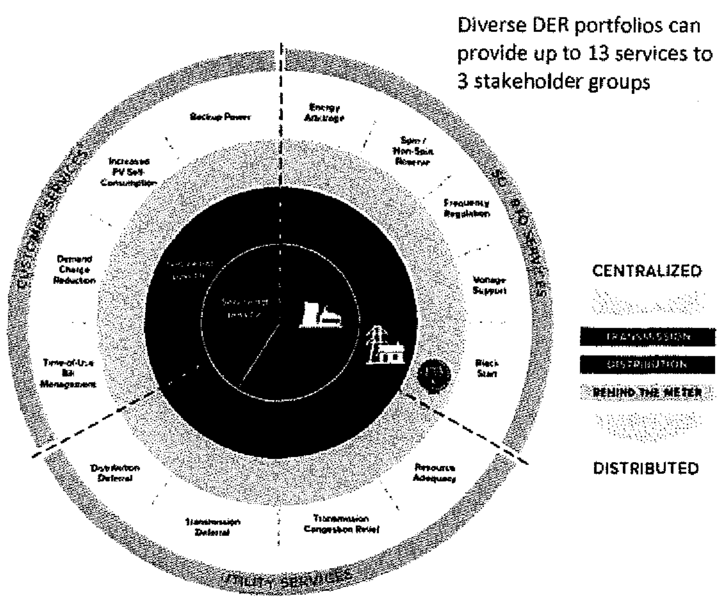
Grid planning for infrastructure investments has historically focused on installing expensive, large assets that provide service over a wide geographic region. This structure naturally evolved from the technology and market characteristics of the original electricity industry, including a natural monopoly, centralized generation, long infrastructure lead times, high capital costs with significant economies of scale, and a concentration of technical know-how within the utility.

Many of these barriers have been eliminated with the technological advancement in physical infrastructure options – such as DER portfolios that can meet grid needs – and increased sophistication of grid design and operational tools. However, grid planning remains focused on utilizing traditional infrastructure to the detriment of harnessing the increasing availability of DERs. Utilizing DER solutions will require a shift in grid planning approaches, as well as increased access to the underlying planning and operational data needed to enable DERs to operate most effectively in concert with the grid.

Distributed Energy Resources Offer Increased Grid Flexibility

Distributed energy resources include assets such as rooftop PV, smart inverters, controllable loads, permanent load shifting, combined heat and power generators, electric vehicles, and energy efficiency resources. These resources provide a host of benefits to the customer, utility, and transmission operator as identified by numerous research organizations including EPRI and the Rocky Mountain Institute (RMI). As depicted in the RMI figure to the right, diverse portfolios of DERs offer a wide range of grid services at the distribution, transmission, and customer levels.[9]

Distributed energy resources can offer deferral and avoidance of planned grid investments, improved grid resiliency, and increased customer choice. DERs, if deployed effectively and placed on equal footing in the planning process with traditional grid investments, can ultimately lead to increased net benefits for ratepayers.



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II. Distributed Energy Resources Offer a Better Alternative

Motivated by the challenge faced in designing a grid appropriate to the 21st century, this report first focuses on determining the quantifiable net economic benefits that DERs can offer to society. The approach taken builds on existing avoided cost methodologies – which have already been applied to DERs by industry leaders – while introducing updated methods to hard-to-quantify DER benefit categories that are excluded from traditional analyses. While the final net benefit calculation derived in this report is specific to California, the overall methodological advancements developed here are applicable across the U.S. Moreover, the ultimate conclusion from this analysis – that DERs offer a better alternative to many traditional infrastructure solutions in advancing the 21st century grid – should also hold true across the U.S., although the exact net benefits of DERs will vary across regions.

A. Methodology

The methodology utilized in this paper is built upon well-established frameworks for valuing policies, programs and resources – frameworks that are grounded in the quantification of the costs and benefits of distributed energy resources. Specifically, the methodology employed here:

1. Begins with the Electric Power Research Institute's 2015 Integrated Grid/Cost Benefit Framework in order to quantify total net societal costs and benefits in a framework that applies nationally. [10]
2. Quantifies the benefits for the state of California, where the modeling of individual cost and benefit categories is possible using the California Public Utilities Commission 2015 Net Energy Metering Successor Public Tool.[11] Within the context of California, this report's DER avoided cost methodology is expanded beyond EPRI's base methodology to incorporate commonly recognized (although not always quantified) categories of benefits and costs, while also proposing methodologies for several hard-to-quantify categories using the Public Tool.
3. Incorporates the full costs of DER integration, including DER integration cost data as identified by California utilities in their 2015 Distribution Resource Plans[12] to determine the net benefits of achieving 2020 penetration levels.
4. Repeats the methodology in a concrete case study by applying it to the planned distribution capacity projects from the most recent Phase I General Rate Case in California.

Enhancing Traditional Cost/Benefit Analysis and Describing Benefits as Avoided Cost

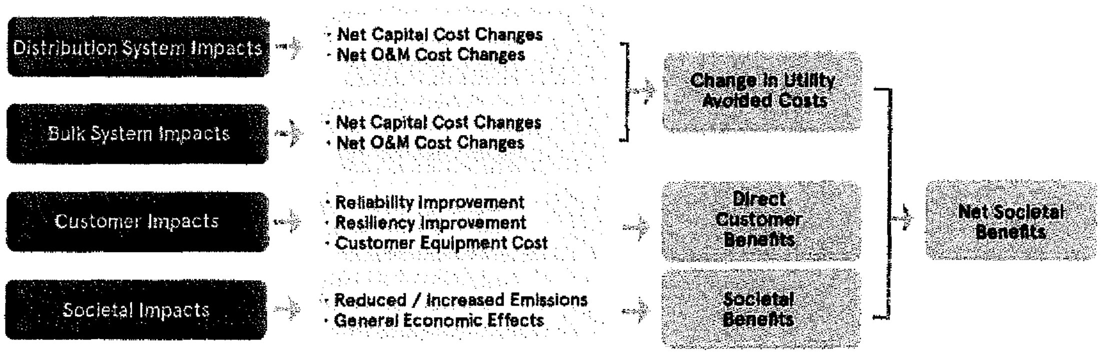
Cost/benefit analyses have been conducted for many decades to evaluate everything from utility-owned generation to utility-administered customer programs such as energy efficiency rebates and demand response program funding. This paper replicates established methodologies wherever possible, and offers new or enhanced methodologies where appropriate to consider new benefit categories that are novel to customer-driven adoption of DERs, and therefore often excluded from traditional analyses.

A key component of cost/benefit analysis commonly used for valuing the benefits of DER is the avoided cost concept, which considers the benefits of a policy pathway by quantifying the reduction in costs that would otherwise be incurred in a business-as-usual trajectory. While avoided cost calculations can be performed with varying scopes,[13] there is some degree of consensus on what the appropriate value categories are in a comprehensive avoided cost study. Groups like IREC,[14] RMI[15] and EPRI[16] have attempted to take these standard valuation frameworks even further, describing general methods for valuing some of the benefit categories that are often excluded from traditional analyses.

Each step taken by researchers to enhance previously used avoided cost methodologies advances the industry beyond outdated historical paradigms. DER-specific methodological updates include the consideration of new types of avoided costs that could be provided by distributed resources, or a revision of the assumption that resources adopted by customers are uncontrollable, passive deliverers of value to the grid and that proactive planning and policies cannot or will not be implemented to maximize the value of these grid-interactive resources.

This report continues the discussion using EPRI's 2015 Integrated Grid/Cost Benefit Framework as a springboard. EPRI's framework, depicted in the following image) was chosen as it is the most recently published comprehensive cost/benefit analysis framework for DERs. This report assumes a basic familiarity with EPRI's methodology – or avoided cost methodologies in general – on the part of the reader, although explanations of each cost or benefit category are included in the following section.

EPRI Cost/Benefit Framework[17]



The Value of DERs within California

While the overall methodology enhanced within this report is applicable nationwide, the focus of this report's economic valuation of DERs in the cost/benefit analysis is limited to the state of California. For California's NEM 2.0 proceeding, the energy consulting firm Energy+Environmental Economics (E3) created a sophisticated model that parties used to determine the impact of various rate design proposals. A major component of this model was the ability to assess DER avoided costs under different input assumptions. The more traditional avoided cost values in this paper are derived from the inputs used in the NEM 2.0 proposal filing of The Alliance of Solar Choice (TASC) for the E3 model, which is available publicly online.[18]

Additionally, benefit and cost categories for DERs – along with accompanying data and quantification methods – are being developed in the CPUC Distribution Resource Plans (DRP) proceeding. This update of the DER valuation framework in the DRP proceeding, however, is not present in the existing methodologies being used to quantify the benefits of rooftop solar in California as part of the NEM 2.0 proceeding due to the concurrent timing of the two proceedings. This report bridges these two connected proceedings in its economic analysis of the value of DERs within California.

While evaluating net societal benefits at the system level in California is a key step in understanding the total potential value of DERs, there remains much discussion within the industry regarding whether calculated net benefits can actually be realized from changes in transmission and distribution investment planning. To this end, this analysis applies the developed California DER valuation framework to a real-world case study utilizing the latest GRC filed in California, PG&E's 2017 General Rate Case Phase I filing. By utilizing this third dataset, in addition to the NEM 2.0 and DRP proceedings, this analysis delivers a comprehensive and up-to-date consideration of the potential value DERs can provide to the grid.

Analysis Scope, Assumed Scenario, and End State

This report evaluates the benefits of customer DER adoption, the associated costs, and the resulting net benefit/cost.

DESCRIPTION OF SCOPE	
Net Societal Benefit = Societal Benefits – Societal Costs	
Societal Benefits	The benefits that would be generated if California achieved high-penetration of distributed energy resources.
Societal Costs	The investment cost that would be necessary to enable California to achieve high-penetration of distributed energy resources.
Net Societal Benefits	The value to society of achieving a high-penetration California defined as the benefits of the outcome less the costs of achieving the outcome.

The benefits and costs of DER are highly dependent on penetration levels. Therefore, this analysis utilizes a set of common assumptions for expected DER penetration, and specifies a market end state scenario upon which benefits and costs are quantified. The end-state assumed in this report utilizes scenarios in Southern California Edison's (SCE) July 1, 2015 Distribution Resource Plan, which includes DER adoption levels and integration cost estimates for the 2016-2020 period. These integration costs inform DER penetration assumptions, which are applied consistently across the benefits calculations to ensure that the costs of low penetration are not attributed to the benefits of high penetration, and vice-versa.

Incremental DER Adoption Scenario for 2016-2020

TECHNOLOGY	QUANTITY
Solar	4.5 GW
With Storage	900 MWh (10% Adoption)
With Load Control	150 MW (20% Adoption)

To simplify the discussion, solar deployment is focused on the years 2016-2020, adopting the penetration levels and costs associated with the TASC reference case as filed in the CPUC NEM 2.0 proposal filing, which corresponds approximately to SCE's Distribution Resource Plan Scenario 3. Of the approximately 900,000 new solar installations expected to be deployed during this period, SolarCity estimates 10% would adopt residential storage devices and 20% would adopt controllable loads (assumptions are based on customer engagement experience and customer surveys). These adoptions are central to the ability of customer DER deployments to defer and avoid traditional infrastructure investments as assessed in this paper.

The assumptions described above are used to complete the cost/benefit analysis of DERs for the whole of California. After evaluating net societal benefits at the system level, the methodology is then applied to a particular case study of actual distribution projects proposed under the latest GRC filed within California, PG&E's 2017 General Rate Case Phase I filing.

In the following sections, the deployment scenario is evaluated both qualitatively and quantitatively under a cost-benefit framework that is grounded in established methodologies, but enhanced to consider the impact of such a large change in the way the electric system is operated. The study consolidates a range of existing analyses, reports and methodologies on DERs into one place, supporting a holistic assessment of the energy policy pathways in front of policy-makers today.

B. Avoided Cost Categories

The avoided cost categories evaluated in this report are summarized in the following table. The first seven categories are included within traditional cost-benefit analyses, and as such are not substantially extended in this report (see Appendix for methodological overviews and TASC NEM Successor Tariff filing for comprehensive descriptions and rationale on assumptions[19]). The next five categories (in yellow highlight) represent new methodology enhancements to hard-to-quantify avoided cost categories (i.e. benefit categories) that are often excluded from traditional analyses. In this section, we detail the methodology and rationale for quantifying these five avoided cost categories.

AVOIDED COST	DESCRIPTION
Energy + Losses	The value of wholesale energy that would otherwise be generated in the absence of DERs, adjusted for losses that would occur. In CA, the cost of carbon allowances from the Cap and Trade program is embedded in the wholesale energy value
Generation Capacity	The value of avoiding the need for system generation capacity resources to meet peak load and planning reserve requirements
Transmission Capacity	The value of avoiding the need to expand transmission capacity to meet peak loads
Distribution Capacity	The value of avoiding the need to expand distribution capacity to meet peak loads
Ancillary Services	The value of a reduced need for operational reserves based on load reduction through DERs
Renewable Energy Compliance	The value of reducing procurement requirements for renewable energy credits, due to reduced delivery of retail energy on which RPS compliance levels are based
Societal Benefits	The value of benefits that accrue to society, and are not costs directly avoided by the utility
Voltage and Power Quality	The value of avoiding or reducing the cost required to maintain voltage and frequency within acceptable ranges for customer service
Conservation Voltage Reduction	The value of enabling conservation voltage reduction benefits by providing localized voltage support
Equipment Life Extension	The value of extending the useful life and improving the efficiency of distribution infrastructure by reducing load and thermal stress equipment
Reliability & Resiliency	The value of avoiding or reducing the impact outages have on customers
Market Price Suppression	The value of reducing the electric demand in the market, hence reducing market clearing prices for all consumers of electricity

Voltage, Reactive Power, and Power Quality Support

Solar PV and battery energy storage with 'smart' or advanced inverters are capable of providing reactive power and voltage support, both at the bulk power and local distribution levels. At the bulk power level, smart inverters can provide reactive power support for steady-state and transient events, services traditionally supplied by large capacitor banks, dynamic reactive power support, and synchronous condensers. For example, in Southern California the abrupt retirement of the San Onofre Nuclear Generation Station (SONGS) in 2013 created a local shortage of reactive power support, endangering stable grid operations for SCE in the Los Angeles Basin area. To meet this reactive power need, SCE sought approval to deploy traditional reactive power equipment at a cost of $200-$350 million, as outlined in the table below. DERs were not included in the procurement to meet this need. Had DERs with smart inverters been evaluated as part of the solution, significant reactive power capacity could have been obtained to avoid the deployment of expensive traditional equipment.

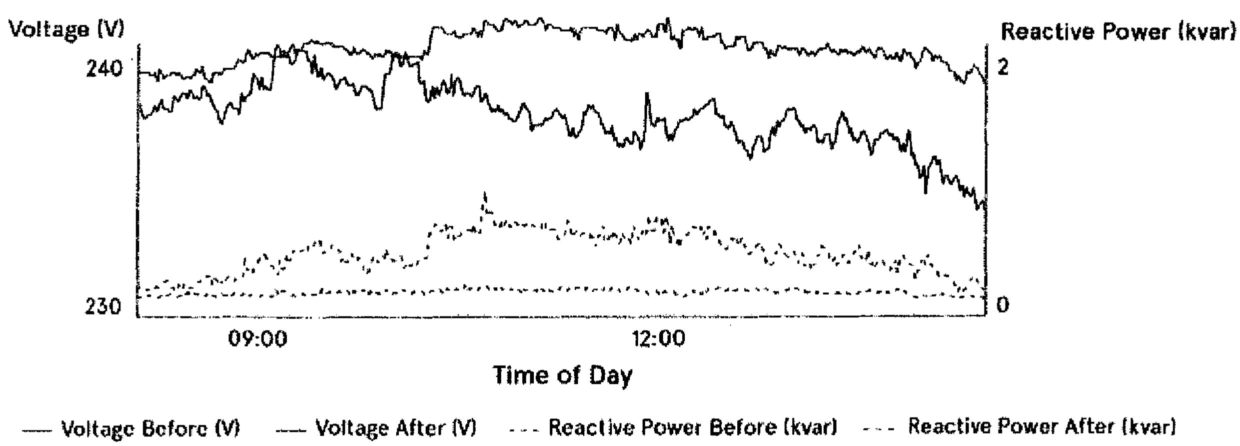
SONGS Reactive Power Replacement Projects

PROJECT	CAPACITY (MVAR)	IN-SERVICE	COST
Huntington Beach Synchronous Condensers	280	6/1/2013	$4.75M
Johanna and Santiago 220 kV Capacitor Banks	160	7/1/2013	$1.1-10M $10-50M
Viejo 220 kV Capacitor Banks	160	7/1/2013	$1.1-10M $10M $10-50M
Talega Area Dynamic Reactive Support	250	6/1/2015	$58-72M
South Orange County Dynamic Reactive Support	400	12/1/2017	$50-75M
Penasquitos 230 kV Synchronous Condenser	240	5/1/2017	$56-70M
Total	**1,400**		**$201-$352M**

Sources[20,21,22,23,24,25,26,27]

At the distribution level, smart inverters can provide voltage regulation and improve customer power quality, functions that are traditionally handled by distribution equipment such as capacitors, voltage regulators, and load tap changers. While the provision of reactive power may come at the expense of real power output (e.g. such as power otherwise produced by a PV system), inverter headroom either exists or can readily be incorporated into new installations to provide this service without impacting real power output. The capability of DER smart inverters to provide voltage and power quality support is currently being demonstrated in several field demonstration projects across the country. For instance, a demonstration project in partnership with an investor-owned utility is currently demonstrating the voltage support from a portfolio of roughly 150 smart inverters controlling 700kW worth of residential PV systems. The chart below depicts the dynamic reactive power delivered to support local voltage. In this instance, smart inverter support resulted in a 30% flatter voltage profile.[28]

Reactive power and voltage support from a smart inverter



Projects such as the SONGS reactive power procurement project provide recent examples where utility investment was made for reactive power capacity. These projects were used to quantify the economic benefit of DERs providing reactive power support. To do so, a corresponding $/kVAR-year value was applied to the inverter capacity assumed in the deployment scenarios to determine the value of the services offered by the DER portfolio. Note, also, that markets including NYISO, PJM, ISO-NE, MISO, and CAISO already compensate generators for capability to provide and provision of reactive power.[29]

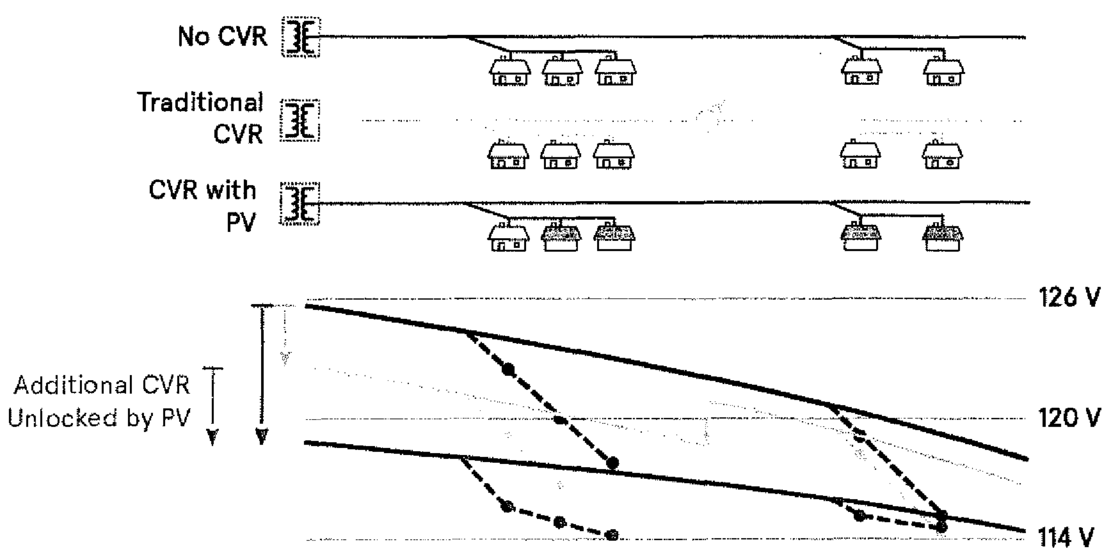
Conservation Voltage Reduction

Smart inverters can enable greater savings from utility conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that reduces customer service voltages in order to achieve a corresponding reduction in energy consumption. CVR programs are often implemented system-wide or on large portions of a utility's distribution grid in order to conserve energy, save customers on their energy bills, and reduce greenhouse gas emissions. CVR programs typically save up to 4% of energy consumption on any distribution circuit.[30] The utilization of smart inverters is estimated to yield another 1-3% of incremental energy consumption savings and greenhouse gas emissions reductions.

From an engineering perspective, CVR schemes aim to reduce customer voltages to the lowest allowable limit as allowed by American National Standards Institute (ANSI) standards. However, CVR programs typically only control utility-owned distribution voltage regulating equipment, changes to which affect all customers downstream of any specific device. As such, CVR benefits in practice are limited by the lowest customer voltage in any utility voltage regulation zone (often a portion of a distribution circuit), since dropping the voltage any further would violate ANSI standards for that customer.

Since smart inverters can increase or decrease the voltage at any individual location, DERs with smart inverters can be used to more granularly control customer voltages in CVR schemes. For example, if the lowest customer voltage in a utility voltage regulation zone were to be increased by, say, 1 Volt by controlling a local smart inverter, the entire voltage regulation zone could then be subsequently lowered another Volt, delivering substantially increased CVR benefits. Such an example is depicted in the image below, where the green line represents a circuit voltage profile where smart inverters support CVR. Granular control of customer voltages through smart inverters can dramatically increase CVR benefits.

DERs control voltage locally and enable CVR

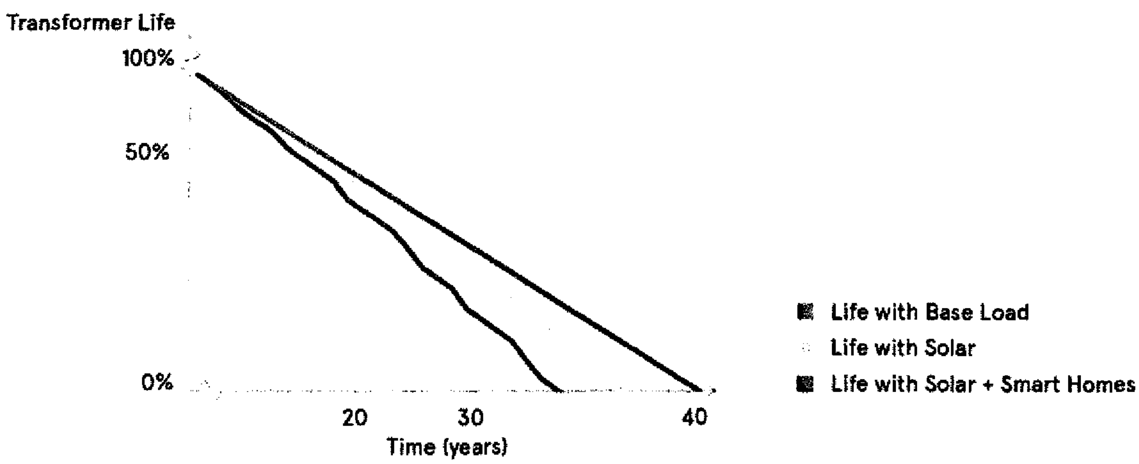


Equipment Life Extension

Either through local generation, load shifting, and/or energy efficiency, DERs reduce the net load at individual customer premises. A portfolio of optimized DERs dispersed across a distribution circuit in turn reduces the net load for all equipment along that distribution circuit. Distribution equipment, such as substation transformers, operating at reduced loading will benefit from increased equipment life and higher operational efficiency.

Distribution equipment may operate at very high loading during periods of peak demand, abnormal configuration, or emergency operation. When the nominal rating of equipment is exceeded, or overloaded, the equipment suffers from degradation and reduction in operational life. The more frequently that equipment is overloaded, the more that such degradation occurs. Furthermore, the efficiency of transformers and other grid equipment falls as they perform under increased load. The higher the overload, the larger the efficiency losses. Utilities have significant portions of their grid equipment that regularly operate in overloaded fashion. DERs' ability to reduce peak and average load on distribution equipment therefore leads to a reduction in the detrimental operation of the equipment and an increase in useful life, as shown in the following figure. The larger the peak load reduction, the larger the life extension and efficiency benefits.

Distributed Energy Resources Extend Transformer Life



To quantify these benefits, medium to large liquid-filled transformers were modeled with typical load and DER generation profiles. The magnitude of the reduced losses and resulting equipment degradation avoidance were calculated using IEEE C57.12.00-2000 standard per unit life calculation methodology.[31,32] DERs such as energy storage are able to achieve an even greater avoided cost than solar alone, as storage dispatch can more closely match the distribution peak. Quantified benefits contributing to net societal benefits calculation include the deferred equipment investment due to extended equipment life and reduced energy losses through increased efficiency.

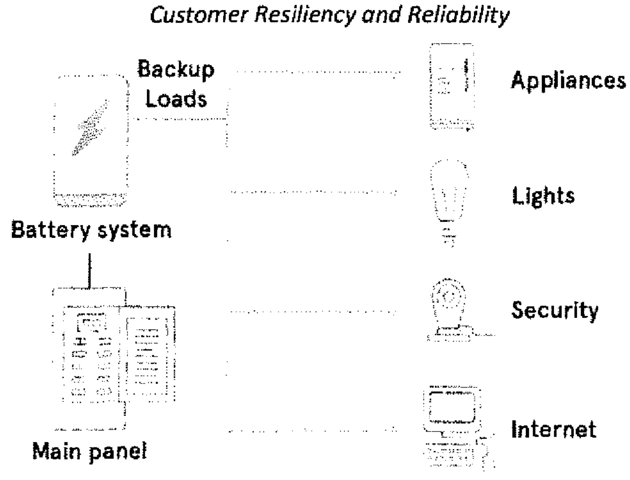
Note that non-optimized DERs can be cited as having negative impact on equipment life. While highly variable generation and load can negatively impact equipment life – such as driving increased operations of line regulators – optimized and coordinated smart inverters mitigate this potential volatility impact on equipment life.

Resiliency and Reliability

DERs such as energy storage can provide backup power to critical loads, improving customer reliability during routine outages and resiliency during major outages. The rapidly growing penetration of batteries combined with PV deployments will reduce the frequency and duration of customer outages and provide sustained power for critical devices, as depicted in the adjacent figure.

Improved reliability and resiliency has been the goal of significant utility investments, including feeder reconductoring and distribution automation programs such as fault location, isolation, and service restoration (FLISR). Battery deployments throughout the distribution system can eventually reduce utility reliability and resiliency investments. However, this analysis utilizes a conservative approach, only considering average customer savings from reduced outages and excludes avoided utility investments.

Distributed Energy Resources Improve Customer Resiliency and Reliability



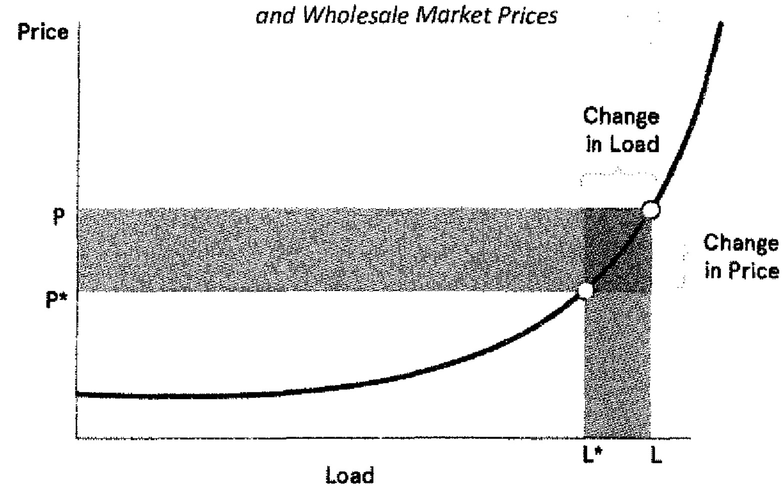
To quantify near-term reliability and resiliency benefits, the value of lost load as calculated by Lawrence Berkeley National Lab[33] was applied to the energy that could be supplied during outages. Outages were based on 2014 CPUC SAIFI statistics.

Market Price Suppression Effect

Wholesale electricity markets provide a competitive framework for electric supply to meet demand. In general, as electric demand increases market prices increase. DERs can provide value by reducing the electric demand in the market, leading to a reduction in the market clearing price for all consumers of electricity. This effect was recently validated in the U.S. Supreme Court's decision to uphold FERC Order 745, noting that operators accept demand response bids if and only if they bring down the wholesale rate by displacing higher-priced generation. Notably, the court emphasized that "when this occurs (most often in peak periods), the easing of pressure on the grid, and the avoidance of service problems, further contributes to lower charges."[34] As a behind-the-meter resource, rooftop solar impacts wholesale markets in a similar way to demand response, effectively reducing demand and thus clearing prices for all resources during solar production hours. While the CPUC Public Tool attempts to consider the avoided cost of wholesale energy prices, it does not consider the benefits of reducing wholesale market clearing prices from what they would have been in the absence of solar.

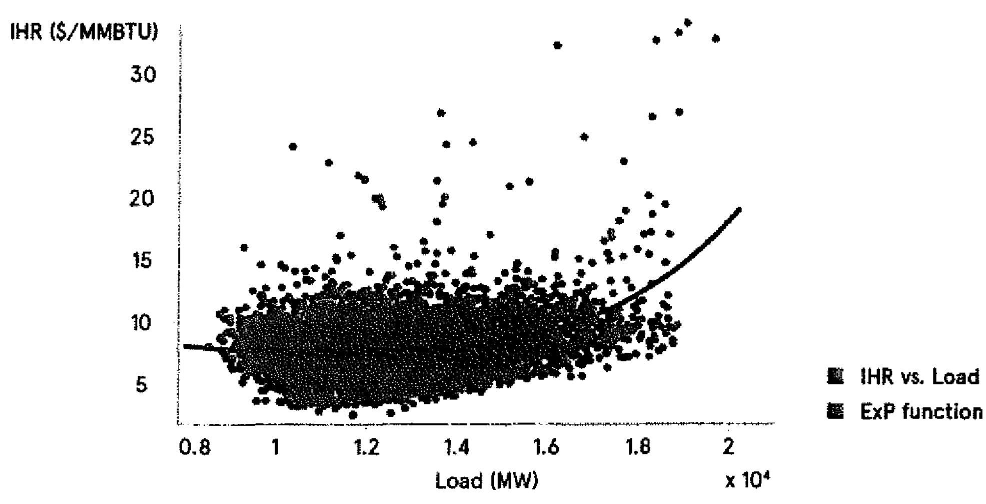
This effect is illustrated in the adjacent figure. In the presence of DERs, energy prices are at the lower "P*" price which otherwise would have been at the higher "P" price absent the DERs. Market price suppression could then be quantified as the difference between prices multiplied by load, or $(P - P^*) * L^*$.

Relationship between Electric Demand and Wholesale Market Prices



To quantify the magnitude of cost reductions due to market price suppression, this report estimates the relationship between load and market prices based on historical data. It is important to isolate other driving factors to only capture the effect of load change on prices. One of these driving factors is natural gas prices, which directly impacts electric prices because the marginal supply resource in California is often a natural gas-fired power plant. This can be isolated by normalizing market prices over gas prices, known as Implied Heat Rate (IHR), and estimating the relationship between IHR and load, which is shown in figure below for PG&E DLAP prices and load.

Relationship between electric demand and Implied Heat Rate for PG&E



Smart energy homes equipped with energy storage are able to achieve an even greater avoided cost than distributed solar alone. Storage devices that discharge in peak demand hours with high market clearing prices can take advantage of the stronger relationship between load and price at high loads.

Results

After establishing the 2016-2020 penetration scenario and defining the methodologies for each category of avoided cost, the CPUC Public Tool was utilized to estimate the benefits of achieving the 2020 penetration scenario. For avoided cost categories the CPUC Public Tool was not able to incorporate, calculations were completed externally using common penetration and operational assumptions for each technology type. In order to be consistent with the CPUC Public Tool outputs, levelized values are expressed in annual terms in 2015 dollars below.

Annual Benefits of 2016-2020 DER Deployments

AVOIDED COST CATEGORY	PV + SMART INVERTER ($M/YEAR)	+DERs ($M/YEAR)	TOTAL ($M/YEAR)
Penetration Levels	*4.5 GW*	*[illegible]0,000 Homes*	
Energy + Losses	$637	$74	$710
Generation Capacity	$91	$99	$190
Transmission Capacity	$333	$42	$375
Distribution Capacity	$187	$54	$241
Ancillary Services	$6	$1	$7
Renewable Energy Compliance	$199	$23	$221
Societal Benefits	$371	$43	$414
Voltage and Power Quality	$91	$7	$99
Conservation Voltage Reduction	$34	$4	$38
Equipment Life Extension	$31	$4	$36
Reliability & Resiliency	$0	$8	$8
Market Price Suppression	$163	$19	$182
Total Benefits	**$2,143**	**$378**	**$2,521**

Previous assessments of high penetration DERs have replicated existing methodologies that have often been applied to passive assets like energy efficiency; however, these approaches fail to recognize the potential value of advanced DERs that will be deployed during the 2016-2020 timeframe. When a more comprehensive suite of benefits that could be generated by DERs today is considered, total benefits of the 2016-2020 DER portfolio in California exceeds $2.5 billion per year.

C. The Costs of Distributed Energy Resources

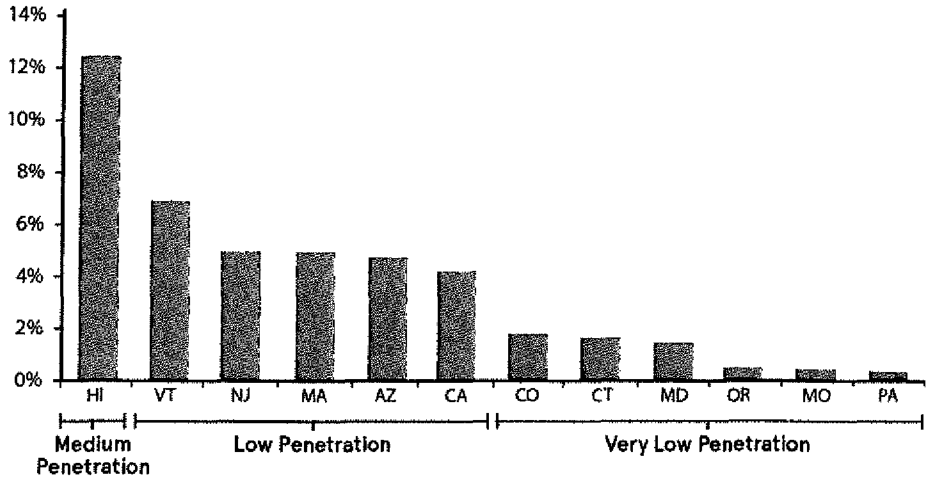
As presented above, distributed resources offer significant ratepayer benefits; however, these benefits are not available without incurring incremental costs to enable their deployment. In order to quantify the net societal benefit of DERs, these costs must be subtracted from the benefits. Costs for distributed energy resources include integration at the distribution and bulk system levels, utility program management, and customer equipment.

Distribution Integration Costs

DERs are a critical new asset class being deployed on the distribution grid which must be proactively planned for and integrated with existing assets. This integration process will sometimes require unavoidable additional investments. However, it is essential to separate incremental DER integration costs from *business as usual* utility investments. Recent utility funding requests for DER integration have included costs above those needed to successfully integrate DERs. This subsection will explore typical DER integration costs and evaluate the validity of each type.

While new DER integration rules of thumb and planning guidelines are emerging,[35] no established approach exists for identifying DER integration investments or estimating their cost. It is clear, however, that integration efforts and costs vary by DER penetration level. Generally, lower DER penetration requires fewer integration investments, while higher penetration may lead to increased investment. As depicted in the following chart, NEM PV penetration levels vary across the U.S.[36] Most states have *very low* (<5%) penetrations, while only Hawaii experiences *medium* (10-20%) penetration. California exhibits *low* (5-10%) penetration overall, although individual circuits may experience much higher penetration.

NEM Solar Capacity as a Percentage of Total System Peak



For this analysis, DER integration costs were developed from estimates submitted by California utilities to the CPUC as part of their Distribution Resource Planning (DRP) filings. This analysis incorporates the specific cost categories and figures from Southern California Edison's filing, since this filing alone included specific cost estimates. In assessing these costs, each proposed investment was reviewed to determine whether it was a required incremental cost resulting from the integration of DERs. If so, it should indeed be included in the cost/benefit calculation. If the investment (or a portion thereof) was determined to be a component of utility *busines as usual* operations, such investment was not included in the analysis.

In order to determine whether a proposed utility investment is required, the following *threshold question* was asked:

- *Would these costs be incurred even in the absence of DER adoption?*

If the costs would be incurred regardless of DER adoption, or if the utility had previously requested regulatory approval for the investment but justified the investment via a program unrelated to DER adoption, then the costs should not be classified as DER integration costs. For example, if a utility had previously requested approval to upgrade (i.e. cutover) 4kV circuits to a higher voltage in order to increase capacity and reliability before DERs were prevalent, yet now associates the upgrade costs to DERs, then the investment should not be attributed to DER integration. This threshold analysis eliminates from consideration or reduces some of the proposed utility integration costs.

Of the remaining costs, each was further assessed by asking the following set of *screening questions*:

- Do more cost effective mitigation measures exist for the proposed investment? Can advanced DER functionalities (e.g. volt/VAR support) mitigate or eliminate the need for the investment?
- Are costs relevant for the forecasted DER penetration levels, or only for much higher penetrations?
- Do stated costs reflect realistic cost figures, or do they reflect inflated estimates?

Several utility integration investments are proposed to mitigate an integration challenge where more cost effective solutions exist. For example, voltage-related concerns due to PV variability are often used to justify replacement of capacitor banks on distribution feeders. However, the use of embedded voltage and reactive power capabilities in smart inverters make the deployment of new capacitor banks redundant and overly expensive in most instances. Furthermore, while some proposed costs may be relevant for high penetrations of DERs – such as bi-directional relays to deal with reverse power flows – these investments may not be necessary at low penetration levels.

The following table presents the DER integration investment categories as identified in SCE's DRP filing according to its Scenario 3 forecast for DER growth in California. SCE's integration costs were scaled up in order to estimate total distribution integration costs for all California utilities; therefore, the table represents total California distribution integration costs over 2016-2020. For each investment, applicability to DER integration is assessed using the threshold and screening questions discussed above, resulting in a quantification of costs that are directly "Applicable to DERs". An overview of the assessment of each high-level integration category is provided in the table, with more detailed technical discussion of each investment type and assessment rationale offered in the Appendix. This cost quantification is necessarily high-level due to the lack of details available for each investment type. As such, more specific assessment is necessary in order to evaluate integration investment plans. This exercise identifies 25% of SCE's DER integration costs, or $1,450 million (or levelized to $189 million annually[37]), as truly applicable to DER integration, which is the number utilized in the cost/benefit analysis in this paper.

CATEGORY	INVESTMENTS	UTILITY COST CLAIM ($M)	APPLICABLE TO DERs (%)
Distribution Automation	Automated switches w/enhanced telemetry, remote fault indicators	$710	0%
Substation Automation	Substation automation, modern protection relays	$691	30%
Communication Systems	Field area network, fiber optic network	$888	0%
Grid Reinforcement	Conductor upgrades to a larger size, conversion of circuits to higher voltage	$1,070	50%
Technology Platforms and Applications	Grid analytics platform/applications, long-term planning tool set, distribution circuit modeling tool, interconnection application processing, DRP data sharing portal, grid/DER management system, system architecture and cyber security, distribution Volt/VAR optimization	$2,337	30%
Total Distribution Integration Costs		**$5,697**	**25% (1,450)**

Bulk System Integration Costs

Integration of variable resources with the bulk power grid is expected to result in an increase in variable operating costs associated with the way the generation fleet is used to accommodate the variability. To quantify this cost, $/MWh values quantifying this cost for a 33% renewable portfolio standard were scaled per calculations adopted by the California PUC.[38]

Utility Program Management Costs

To estimate the incremental utility program costs associated with DER adoption, the default inputs within the Public Tool were used, which include upfront installation and metering costs, as well as incremental billing costs. All told, these costs amounted to $26 million per year based on the level of adoption in the TASC base case scenario.

Customer Equipment Costs

The costs of DERs themselves must be considered, including the cost of equipment, labor, and financing. For solar, CPUC Energy Division staff's reference case solar price forecast is used to determine the cost of deployed equipment in the 2016-2020 timeframe, factoring in the December 2015 extension of the Federal Investment Tax Credit. For storage, the price forecast was based on Navigant Research's projections;[39] for controllable thermostats, current vendor prices were used.

Based on these forecasts, deployments forecasted for the 2016-2020 timeframe yielded a blended average adoption cost of the installed base of $3.86/W for the 2016-2020 timeframe, or $2.70/W after reflecting the 30% Federal Investment Tax Credit (ITC). In absolute terms, the total cost of adoption to Californians translates to $12.1 billion (nominal) for 4.5GW of rooftop solar. For co-located storage and load control, total investment to meet adoption forecasts totals $259 million.

Results

Societal net benefits calculations require a comprehensive consideration of costs that society bears as a result of attaining the specified 2020 penetration levels, including the costs of administering customer programs, grid integration costs needed to accommodate new assets, and the cost of the assets themselves, which are borne by customers. In the table below, each category is quantified, totalling $1.1 billion per year.

CATEGORY	PV + SMART INVERTER ($M/YEAR)	+DERs ($M/YEAR)	TOTAL ($M/YEAR)
Penetration Levels	*4.5 GW*	*90,000 homes*	
Utility Program Management Costs	$24	$3	$26
Integration Costs (Distribution + Bulk)	$170	$20	$189
Customer Equipment Costs	$770	$119	$889
Total Costs	**$964**	**$141**	**$1,105**

D. *Quantifying Net Benefits*

In this section, we complete EPRI's Cost/Benefit analysis by comparing benefits and costs of DERs during the 2016-2020 deployment timeframe. For consistent comparisons, levelized costs and benefits are based on the year 2020, with all benefits and costs values translated to 2015 dollars.[40]

Establishing a common DER penetration scenario and converting all benefits and costs to net present value terms allows simple summation of each category to provide indicative societal net benefit, suggesting a significant societal value for widespread DER adoption. In total, the benefits of the analyzed scenario are $2.5 billion per year, compared to costs of $1.1 billion per year, resulting in a net societal benefit to Californians of $1.4 billion per year by 2020.

Results of EPRI Societal Net Benefit Test

	CATEGORY	PV+SMART INVERTER ($M/YEAR)	+DERS ($M/YEAR)	TOTAL ($M/YEAR)
Benefits	Energy + Losses	$637	$74	$710
	Generation Capacity	$91	$99	$190
	Distribution Capacity	$333	$42	$375
	Transmission Capacity	$187	$54	$241
	Ancillary Services	$6	$1	$7
	Renewable Energy Compliance	$199	$23	$221
	Voltage and Power Quality	$91	$7	$99
	Conservation Voltage Reduction	$34	$4	$38
	Equipment Life Extension	$31	$4	$36
	Reliability & Resiliency	$0	$8	$8
	Market Price Suppression	$163	$19	$182
	Societal Benefits	$371	$43	$414
	Total Benefits	**$2,143**	**$378**	**$2,521**
Costs	Program Costs	$24	$3	$26
	Integration Costs	$170	$20	$189
	Equipment Costs	$770	$119	$889
	Total Costs	**$964**	**$141**	**$1,105**
	Total Net Benefits			**$1,416**

E. *Case Study: PG&E's Planned Distribution Projects in 2017 General Rate Case*

In the previous section, categories of avoided costs were described and the corresponding values were quantified for the state of California. In this section, the same methodology is applied to PG&E's planned distribution projects from its most recent PG&E 2017 General Rate Case filing from September 2015.

Every three years, California utilities seek approval to recover expenses and investments, including a target profit level, that are deemed necessary for the prudent provision of utility services. For perspective, half of customer's utility payments were driven by the "wires" component of the electric grid in 2014[41] and California's investor owned utilities are expected to add $143 billion of new capital investment into their distribution rate bases through 2050.[42]

Despite the significant size of this avoided cost category, DERs have historically been considered passive assets having little potential on the "wires" side of the business. While not all distribution investment can be avoided by DERs, some of the currently-planned projects are being implemented to accommodate demand growth and replacement of aging assets; these projects could instead be deferred or avoided by DERs. While the CPUC Public Tool uses a generalized treatment of distribution capacity avoided costs to estimate the potential value of deferrals across utilities, more specific values are used in this section sourced from publicly available documents.

The table below summarizes the large capacity-related distribution projects detailed in PG&E's General Rate Case. PG&E seeks approval of $353 million for these distribution system investments.[43] When this $353 million PG&E capital investment is adjusted to factor in the ratepayer perspective – which includes the lifetime cost of the utility's target profit level and recovery of costs related to operations and maintenance, depreciation, interest and taxes from ratepayers – the net present societal cost to PG&E ratepayers of these distribution capacity projects is approximately $586 million.[44] This $586 million cost to ratepayers adds over 1GW of conventional distribution capacity but addresses only 256 MW of near-term capacity deficiencies on PG&E's distribution system when deployed.

Summary of PG&E Electric Distribution Capacity Request – 2017 GRC[45]

Net Present Ratepayer Cost of Capital Investment ($M)[46]	**$586**
Near-term GRC Forecast Deficiency Addressed (MW)	**256**

Based on this societal cost, we consider the net benefits of an alternative, DER-centric solution, which relies on solar with smart inverters, energy storage and controllable thermostats. Due to lack of sufficient detail from PG&E's General Rate Case regarding the operational profiles of the electric distribution capacity projects in question, a simplifying assumption of 75% is used for the DER portfolio's distribution load carrying capacity ratio, which is based on the CPUC's Public Tool default peak capacity allocation factors (PCAF) for PG&E's distribution planning areas. This load carrying capacity ratio reflects capabilities based on customer adoptions with a storage sizing ratio of 2 kWh of energy storage for every 1 kW of PV capacity, or approximately 10 kWh of energy storage for a customer with 5kW of solar installed, as well as a controllable thermostat.

In order to accurately compare the DER solution, the full lifetime cost of the DER solution is considered, which includes the costs of additional DERs that would be needed to accommodate load growth over the lifetime of the conventional solution – assumed to be 25 years. This DER solution deployment schedule, which continuously addresses incremental capacity needs on the grid, contrasts with the traditional, bulky solution deployment schedule, which requires a large upfront investment for capacity to address a small, incremental near-term need. While a DER solution delivers sufficient capacity in each year to provide comparable levels of grid services, deployments occur steadily over time rather than in one upfront investment.

This approach highlights one of the key potential benefits of utilizing a DER solution over a traditional, bulky grid asset: DERs can be flexibly deployed in small bundles over time, a benefit that is further explored in Section IV on the benefits of transitioning to more integrated distribution planning.

Using these assumptions, the previous state-wide methodology is applied to DERs avoiding PG&E's planned distribution capacity projects, but two conservative assumptions are made. First, the scope of benefits is limited to a subset of avoided cost categories that would be directly considered by utility planners today for these types of projects. Whereas conventional equipment used to meet distribution capacity projects are generally unidimensional resources providing a single source of value – distribution capacity – DERs provide multiple sources of value. Second, we base our calculations on PG&E's lower avoided cost values,[46] rather than our own, to demonstrate that there are net benefits even under a conservative scenario.

In addition to avoiding the ratepayer cost of $586 million for planned distribution capacity projects, the DERs deployed to avoid PG&E's distribution capacity projects also avoid $946 million in energy purchases and $79 million and $99 million in generation capacity and avoided renewable energy credit purchases, respectively, totaling $1,709 million in benefits. On the cost side, program costs, integration costs and equipment costs for the associated DERs total to $1,605 million, resulting in a net present value to PG&E ratepayers of $104 million. This net benefit result is particularly notable given the limited scope of benefits considered in this case study and the reliance on PG&E's lower avoided cost values.

Net Benefit of DER Solutions to PG&E Electric Distribution Capacity Request – 2017 GRC
(Calculations Based on PG&E Cost and Benefit Assumptions)

TYPE	CATEGORY	SOURCE	NPV (2015 $M)
Benefits	Energy + Losses	PG&E NEM Successor Filing [48]	$946
	Generation Capacity[49]	PG&E NEM Successor Filing	$79
	Distribution Capacity	PG&E 2017 General Rate Case	$586
	Transmission Capacity	Not Included	-
	Ancillary Services	Not Included	-
	Renewable Energy Compliance	PG&E NEM Successor Filing	$99
	Voltage and Power Quality	Not Included	-
	Conservation Voltage Reduction	Not Included	-
	Equipment Life Extension	Not Included	-
	Reliability & Resiliency	Not Included	-
	Market Price Suppression	Not Included	-
	Societal Benefits	Not Included	-
	Total Benefits		**$1,709**
Costs	Program Costs	PG&E Nem Successor Filing	$55
	Integration Costs	SCE DRP with SolarCity Revisions	$363
	Equipment Costs	PG&E NEM Successor Filing	$1,188
	Total Costs		**$1,605**
	Total Net Benefits		**$104**

In this section, the data available to third-parties around distribution capacity projects from the most recent California Phase I General Rate Case (PG&E's 2017 GRC filing) was used to explore the potential benefits of leveraging DERs to avoid conventional distribution capacity-related investments. Calculations were performed based on PG&E's own avoided cost assumptions from NEM Successor Tariff filings and General Rate Case filings. Results indicate that deploying DER solutions in lieu of PG&E's planned distribution capacity expansion projects in its 2017 GRC could yield net benefits, even looking only at the energy, capacity, and renewable energy compliance values of the DER solutions. While not preferred, simplified assumptions were used to fill missing sources of information and data (e.g. distribution peak capacity allocation factors and forecasted load growth) where necessary. That such simplifying assumptions are necessary highlights the need for additional data sharing on specific infrastructure projects in order to assess the potential of DERs to offset these investments.

III. Utility Regulatory Incentives Must Change in Order to Capture DER Benefits

Section II demonstrated how California could realize an additional $1.4 billion per year by 2020 in net benefits from the deployment of new DERs during the 2016-2020 timeframe. This state-wide methodology was then applied to the planned distribution capacity projects for California's most recent GRC request, showing how the deployment of DERs in lieu of planned distribution capacity expansion projects in PG&E's next rate case could save customers over $100 million.

Despite this potential value from embracing a distribution-centric grid, utilities face institutional barriers to realizing these benefits. Reducing the size of a utility's ratebase – its wires-related investments – cuts directly into shareholder profits. Expecting utilities to proactively integrate DERs into grid planning, when doing so has the potential to adversely impact shareholder earnings, is a structurally flawed approach. It will be impossible to completely capture the potential benefits of DERs until the grid planner's financial conflict with the deployment of DERs is neutralized.

Incentive Barriers

Realigning the incentives of the grid planner to solely focus on delivering a safe, reliable and affordable grid, regardless of the ownership and service models that materialize in the market, is a necessary first step to realize the potential of DERs. There are two fundamental paths forward to address this conflict of interest.

The first path towards realizing this objective would be to separate the role of distribution planning, sourcing, and operations from the role of distribution asset owner, similar to the evolution of Independent System Operators (ISOs) and Regional Transmission Operators (RTO) at the bulk system level. FERC's decree to create independent operators in Order 2000 was driven by the observation that the lack of independent operation of the bulk power system enabled transmission owners to continue discriminatory operation of their systems to favor their own affiliates and further their own interests.[47]

However, while an independent distribution system operator (IDSO) is an appealing governance model, some state regulators may choose a second path for addressing the utility conflict of incentives: maintaining the utilities' traditional role in planning and operating the distribution grid, while neutralizing the misalignment by changing utility incentives. Given the near-term focus in many states on retaining the utility's current role in grid planning and operation, this paper chooses to focus on this path and proposes a model that ensures the utility incentive against non-utility owned assets is neutralized.

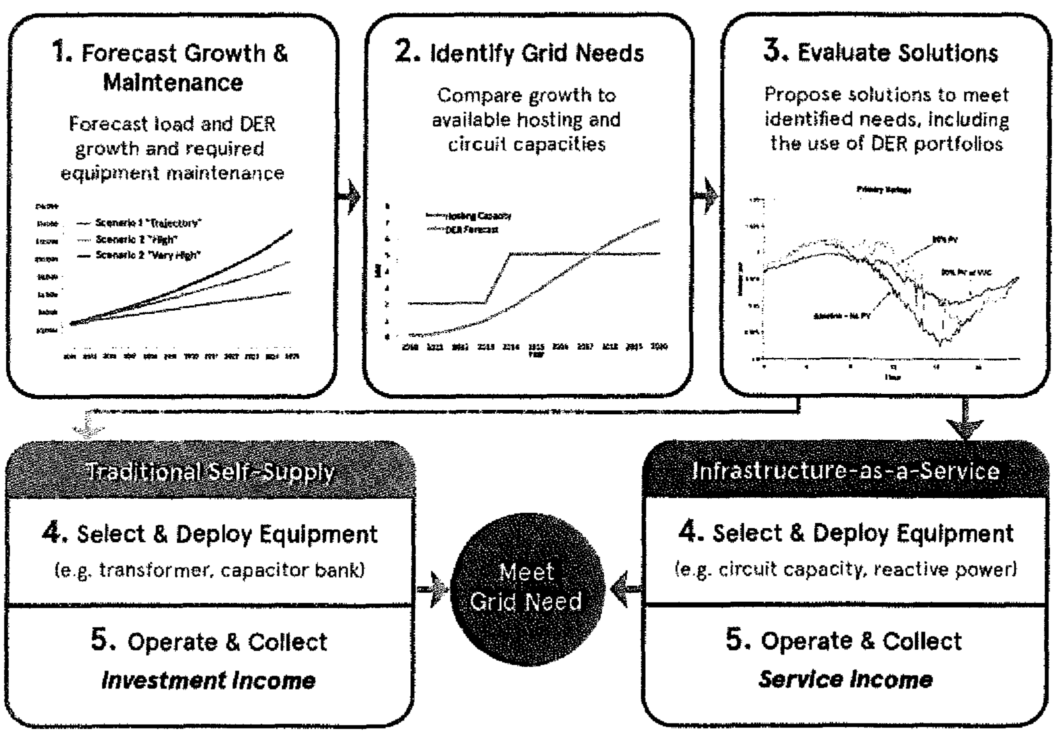
Proposed Solution

In order to ensure least cost/best fit distribution investments in states without an IDSO, this paper proposes the creation of a new utility incentive model, *Infrastructure-as-a-Service,* which would neutralize the utility incentive to deploy utility-owned infrastructure in lieu of more cost-effective third-party options. This model would enable utility shareholders to derive income from third-party grid services, mitigating the financial impact that may bias utility decision-making. Such a model would help ensure that utilities take full advantage of DER readily being adopted by customers.

Infrastructure-as-a-Service

Infrastructure-as-a-Service is a regulatory mechanism that would modify the incentives faced by utilities when sourcing solutions to meet grid needs. This new mechanism would allow utilities to earn income, or a rate of return, from the successful provision of grid services from non-utility owned DERs. Infrastructure-as-a-Service facilitates the least cost/best fit development of distribution grids by creating competitive pathways for DERs to defer or replace conventional grid investments, while maintaining equal or superior levels of safety, reliability, resiliency, power quality, and customer satisfaction. As the figure below shows, the three primary steps of a utility distribution planning process (forecast, identify needs and evaluate solutions) remain identical to the current process, followed by the infrastructure-as-a-Service mechanism's enhancements to sourcing in steps four (select and deploy) and five (operate and collect).[48]

Utility Planning and Sourcing Utilizing Infrastructure-as-a-Service Model



Under the proposed approach, after evaluating all feasible technical solutions for a particular grid need, including alternative grid solutions derived from DER portfolios, Infrastructure-as-a-Service would empower distribution planners to select and deploy third-party assets that address the specified need *if* more cost-effective for ratepayers than conventional solutions. Importantly, Infrastructure-as-a-Service would create an opportunity for utilities to operate and collect streams of service income, or a rate of return, based on the successful deployment of competitively sourced third-party solutions. This service income provides fair compensation for effective administration of third-party contracts that enable alternative resources to deliver grid services, and helps mitigate the structural bias towards utility-owned infrastructure that currently exists under distribution "cost plus" regulation. Note that other mechanisms attempting to achieve a similar utility indifference to DER solutions have been proposed, such as the modified clawback mechanism being discussed in New York.[49] While the clawback mechanism offers the potential to reduce the financial disincentive that utilities face in utilizing DERs, the potential utility upside may be small as compared to the lost opportunity and insufficient to neutralize the utility disincentive. This downside to the clawback mechanism may be overcome via the infrastructure-as-a-service mechanism.

Distribution Loading Order

Neutralizing the utility disincentive to utilizing DERs is critical but not sufficient to drive transformation in distribution planning. New incentives may be ignored in practice without corresponding changes to long-established and familiar utility processes that have sourced only self-supplied solutions to date. The adoption of a Distribution Loading Order[50] would borrow an existing concept from bulk system procurement policy in California, which prioritizes procurement of preferred resources, including energy efficiency, demand response, and renewable energy, ahead of fossil fuel-based sources. In the distribution context, a Distribution Loading Order prioritizes the utilization of flexible DER portfolios over traditional utility infrastructure, when such portfolios are cost-effective and able to meet grid needs. The table below depicts the types of resources that would be prioritized over traditional investments in such a policy.

Distribution Loading Order: Sourcing Solutions

PRIORITY	RESOURCE TYPE	RESOURCE EXAMPLES
1	Distributed Energy Resources	Energy efficiency, controllable loads/demand response, renewable generation, advanced inverters, energy storage, electric vehicles
2	Conventional Distribution Infrastructure	Transformers, reconducturing, capacitors, voltage regulators, sectionalizers

In concert with a mechanism like *Infrastructure-as-a-Service*, a Distribution Loading Order provides the procedural framework for evaluating distribution solutions in order to ensure grid planning is consistent with longer term policy objectives that support environmental, reliability, and customer choice goals. Importantly, a Distribution Loading Order would ensure that DER solutions are properly incorporated into grid planning. However, utilities would always maintain the authority to select and deploy a suitable portfolio of solutions, including conventional solutions when more appropriate, to ensure reliability. For these conventional investments, utilities would continue to earn an authorized rate of return.

Benefits of Infrastructure as a Service

Creating a pathway for DERs to offer grid services in lieu of utility infrastructure investment would be beneficial for utility ratepayers for a variety of reasons.

1. <u>Saves ratepayers money</u>: Allowing full and fair consideration of DER solutions equips grid planners with a broader suite of tools to meet grid needs, resulting in higher infrastructure utilization and lower customer electricity bills.
2. <u>Promotes competition</u>: Expanding the set of suppliers that are eligible to offer distribution solutions unleashes the power of markets to benefit ratepayers. Well-designed competitive markets can deliver superior solutions that are more affordable than those resulting from a self-supply "cost plus" planning model.
3. <u>Increased flexibility and sources the best solution</u>: Sourcing mechanisms that can deliver resources with new desirable characteristics (e.g. granular sizing, fast lead-times, flexible operational traits) into the distribution planners' toolbox creates no-regrets flexibility. And by rendering a utility neutral to the choice of ownership structure, the planner can focus on the singular objective of delivering the least-cost, best-fit solution.
4. <u>Encourages innovation</u>: Providing clear market opportunities for third-party solutions promotes product and service innovation, putting the collective innovation capabilities of all market participants and customers to work.

5. Engages customers: Utilizing DERs to provide grid services increases the capability and willingness of individual customers to actively manage their energy profiles. Ultimately, a neutral decision model like Infrastructure-as-a-Service will help foster the transition from passive ratepayers to proactive customers.

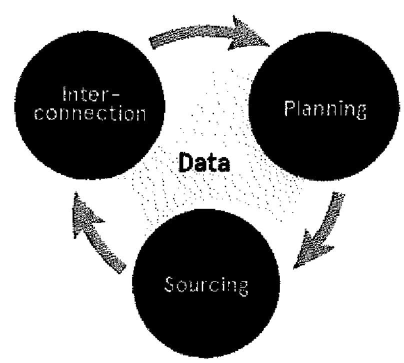
The CPUC recently enhanced the 2016 scope for its Distribution Resource Plan proceeding to formally consider the utility role, business models, and financial interest with respect to DER deployment.[51] Infrastructure-as-a-service is one mechanism to consider that would reduce the conflict of interest towards third-party services inherent in the utility incentive model today. Alternative efforts, such as creating greater functional independence between ownership and operations, as in an IDSO model, should also be explored. Irrespective of the mechanism, an effort to neutralize the utility decision model is needed to ensure that DERs are fully utilized and valued for grid services.

IV. Grid Planning Must be Modernized in Order to Capture DER Benefits

A second structural impediment to fully realizing DER benefits is the current grid planning approach, which biases grid design toward traditional infrastructure rather than distributed alternatives, even if distributed solutions better meet grid needs. Outdated planning approaches rely on static assumptions about DER capabilities and focus primarily on mitigating potential DER integration challenges, rather than proactively harnessing these flexible assets.

A. Adopt Integrated Distribution Planning

Grid planning can be modernized by utilizing an approach to meeting grid needs while at the same time expanding customer choice to utilize DERs to manage their own energy. We call this holistic process *Integrated Distribution Planning.*



Integrated Distribution Planning encourages the incorporation of DERs into every aspect of grid planning. The framework, as depicted in the adjacent figure, expedites DER *interconnections*, integrates DERs into grid *planning*, *sources* DER portfolios to meet grid needs, and ensures *data* transparency for key planning and grid information. Ultimately, the approach reduces overall system costs, increases grid reliability and resiliency, and fosters customer engagement.

If grid planning decisions are made before consideration of customers' decisions to adopt DERs, – which is frequently the case today – grid investments will underutilize the potential of DERs to provide grid services, ultimately resulting in lower overall system utilization and higher societal costs of the collective grid assets. In contrast, prudent planners who proactively plan for customer adoption of DERs may avoid making unnecessary and redundant grid investments, while also enabling the use of customer DERs to meet additional grid needs. Ultimately, planning processes must ensure that DERs are effectively counted on by grid planners and leveraged by grid operators. For more details on integrated distribution planning, see the "Integrated Distribution Planning" white paper overviewing the framework at www.solarcity.com/gridx.

B. Grid Planning Data Must be Transparent and Accessible

The first step in grid planning is to identify the underlying grid needs. As discussed throughout this paper, the use of alternative solutions such as DERs should be included in the portfolio of solutions that are considered to meet these grid needs. While utilities could ostensibly assess these alternative solutions within their existing process, opening up the planning process by sharing the underlying grid data would drive increased competition and innovation in both assessing and meeting grid needs. Any concerns from sharing such data – such as customer privacy, security, data quality, and qualified access – can be mitigated through data sharing practices already common in other industries. In fact, stakeholder engagement and access to planning data is already a central tenet in electric transmission planning across the country. The challenges of ushering a new industry norm of data transparency are far outweighed by the potential that broader data access can drive in increased stakeholder engagement and industry competition.

Data transparency efforts should first focus on communicating the exhaustive list of grid needs that utilities already identify in their planning process. While utilities may claim that such needs are already communicated within general rate cases, the information contained in those filings are incomplete. A standard set of comprehensive data should be shared about each grid need and planned investment so that stakeholders can proactively propose and develop innovative solutions to those needs. This proactive data access broadens the set of innovative solutions made available to utilities and guards against an insular approach to deploying grid investments. The table below is an initial set of minimally-required data to foster adequate stakeholder engagement in regards to specific, utility-identified grid needs.

Data to Foster Engagement in Grid Needs and Planned Investments

DATA NEED	DESCRIPTION
Grid Need Type	The type of grid need (e.g. capacity, reactive power, voltage, reliability, resiliency, spinning/non-spinning reserves, frequency response)
Location	The geographic (e.g. GPS, address) and the system location (e.g. planning area, substation, feeder, feeder node) of the grid need
Scale of Deficiency	The scale of the grid need (e.g. MW, kVAR, CAIDI/SAIDI deficiency)
Planned Investment	The traditional investment to be deployed in the absence of an alternative solution (e.g. 40 MVA transformer, 12kV reconductor, line recloser, line regulator)
Reserve Margin	Additional capacity embedded within the planned investment to provide buffer for contingency scenarios (e.g. 20% margin above expected deficiency embedded within equipment ratings to ensure available capacity during contingency scenarios)
Historical Data	Time series data used to inform identification of grid need (e.g. loading data, voltage profile, loading versus equipment ratings, etc.)
Forecast Data	Time series data used to inform identification of grid need and specification of planned investment (e.g. loading, voltage, and reliability data). Forecast to include prompt year deficiency (i.e. near-term deficiency driver), as well as long-term forecast (i.e. long-term deficiency driver)
Expected Forecast Error	Historical data that includes forecasts relative to actual demands for relevant grid need type in similar projects. Data to be used to evaluate uncertainty of needs and corresponding value of resources with greater optionality (e.g. lead times, sizing, etc.)

While data on specific utility-identified grid needs is critical to assessing innovative solutions in place of traditional investments, underlying grid data should also be made available to foster broader engagement in grid design and operations. Access to underlying grid data allows third parties to improve grid design and operation by proactively identifying and developing solutions to meet grid needs, even before they are identified by utilities. The following data should be made available and kept current by utilities in order to encourage broad engagement in grid design.

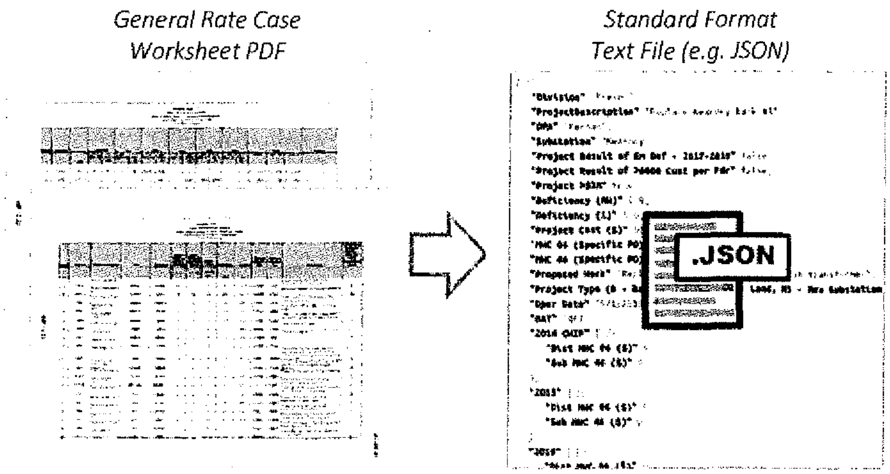
Data to Foster Engagement in General Grid Design and Optimization

DATA NEED	DESCRIPTION
Circuit Model	The information required to model the behavior of the grid at the location of grid need.
Circuit Loading	Annual loading and voltage data for feeder and SCADA line equipment (15 min or hourly), as well as forecasted growth
Circuit DER	Installed DER capacity and forecasted growth by circuit
Circuit Voltage	SCADA voltage profile data (e.g. representative voltage profiles)
Circuit Reliability	Reliability statistics by circuit (e.g. CAIDI, SAIFI, SAIDI, CEMI)
Circuit Resiliency	Number and configuration of circuit supply feeds (used as a proxy for resiliency)
Equipment Ratings, Settings, and Expected Life	The current and planned equipment ratings, relevant settings (e.g. protection, voltage regulation, etc.), and expected remaining life.
Area Served by Equipment	The geographic area that is served by the equipment in order to identify assets which could be used to address the grid need. This may take the form of a GIS polygon.

Share Standardized, Machine-Readable Data Sets

Data that *is* made available on grid needs and planned investments is rarely provided in an accessible format. Often, information is provided in the form of photocopied images of spreadsheet tables within utility GRC filings, hardly a format the enables streamlined analysis. This data communication approach requires stakeholders to manually recreate entire data sets into electronic version in order to carry out any meaningful analysis, a time-intensive and needless exercise. Other potential stakeholders never attempt to engage due to the barrier of data access.

The use of standard, machine-readable data formats is prevalent in many industries and within the utility industry itself; organizations like the Energy Information Agency (EIA) foster such broad access to electronic, standardized data sets. Distribution grid needs and planned investments should follow suit. To illustrate a potential path forward, below is an example of traditional grid capacity needs and corresponding capacity investments as communicated via PG&E's 2017 GRC Phase 1 filing; the image of the text file on the right shows how those same grid needs and planned investments could be translated into a machine-readable format.



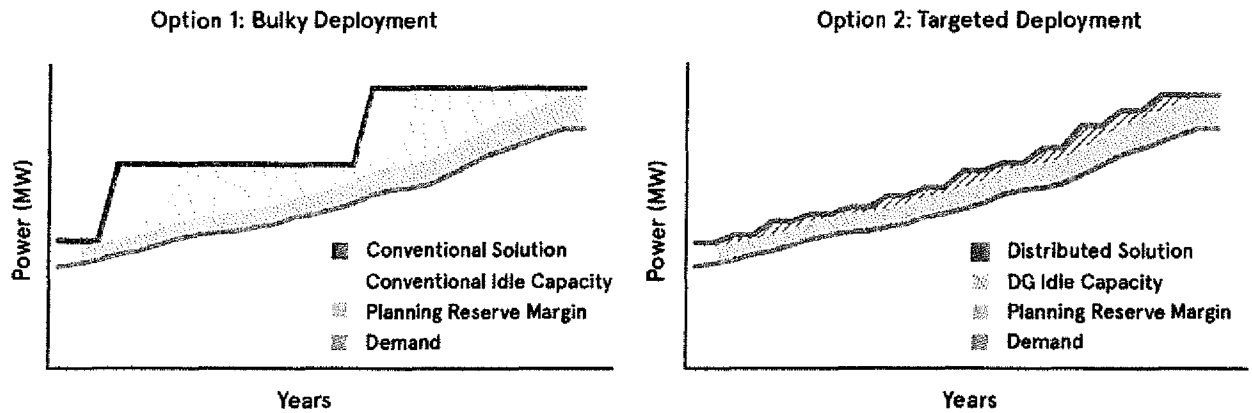
C. *Benefits of Integrated Distribution Planning*

Opening the door to DER solutions in grid planning provides the obvious benefit of a new suite of technological options for grid planners. In some cases, DERs may simply be lower cost on a $/kW basis or more effective at meeting the identified grid need than the conventional solution, making them an obvious choice. DERs, however, also offer an advantage over convertional options due to their targeted and flexible nature, which fundamentally changes the paradigm of grid planning.

Status quo grid planning relies on deploying bulky, traditional infrastructure solutions to address forecasts of incremental, near-term grid needs. In many cases, conventional solutions are 15X larger than the near-term grid need that is driving the actual deployment of the infrastructure.[52] This fundamental reality of grid planning creates two major opportunities for DERs to deliver better value to ratepayers than conventional solutions: 1) utilizing small and targeted solutions, and 2) utilizing the flexibility of DER portfolios.

Value of Small & Targeted Solutions in Modern Distribution Planning

The first source of value is the result of more incremental and targeted investment, which captures the benefit of time value of money. Bulky utility solutions with long equipment lifetimes present a lumpiness challenge for planners. Needs for new resources are driven at the margin, but the available solutions are only cost-effecive when sized to match their long lifetimes, often resulting in low lifetime utilization rates. The significantly smaller building blocks that modern DERs offer planners effectively overcome this historical problem. The figures below compare the deployment timeline of a traditional bulky solution installed to meet demand growth long in the future, relative to a targeted DER solution deployed in small batches to meet continuous demand growth, and the corresponding expectation of idle capacity over time.[53]



Option 1 meets every year's capacity requirement by deploying large solutions infrequently, whereas Option 2 meets annual needs through smaller and more continuous deployments. While the infrastructure deployed with Option 1 will continue to meet the required planning reserve margins decades into the future, it requires a significant upfront investment. Option 2 targets the near-term required planning reserve margins on a continuous basis. Both options ensure that the planning reserve margin for reliability purposes is met, but Option 1 results in higher idle capacity rates over the lifetime of the infrastructure in aggregate when compared to Option 2.

Extending the basic financial idea of the time value of money, paying for capacity today is more expensive than paying for capacity tomorrow – even before considering any cost decreases resulting from technological advancements. DER solutions that can preserve reliability, while delaying capital investments for new capacity until future periods, are inherently valuable to ratepayers. This value driver means that solutions that may look more expensive on a per unit of nameplate capacity basis are actually more cost effective on a net present value basis.

Value of Increased Flexibility in Modern Distribution Planning

The second source of value to be realized from modernizing planning stems from a related but separate challenge that grid planners face: the risk of suboptimal decisions arising from forecast error. This risk is primarily driven by two dynamics:

1. Long lead times are necessary to deploy traditional infrastructure.
2. Long depreciation lifetimes are allowed by regulators for those assets.

As a result, grid planners commonly make investment decisions many years into the uncertain future, and then charge customers for the maintenance, depreciation, profit and taxes associated with those assets over 20 to 30 years or more. Investment under uncertainty imposes risks, which, if not managed properly, create unforeseen ratepayer costs. Among other sources of uncertainty, grid planning and expansion using traditional bulky infrastructure is subject to demand growth uncertainty and technology uncertainty. Both of these forecast errors can be large and expensive.

Over-forecasting demand can result in an overbuilt system for which ratepayers must bear the full burden, even if the infrastructure was not needed. Under-forecasting demand can require the installation of suboptimal, expensive patchwork solutions, or threaten reliability if solutions cannot be provided in time. Similarly, on the technology side, inaccurately forecasting the future costs and capabilities of technologies may result in premature obsolescence as technological advancement dramatically reduces equipment costs or increases equipment efficiency. While private firms typically bear these investment risks in other industries, utility ratepayers bear 100% of these forecast error risks in the electric industry unless the utility regulator acts to disallow cost recovery.

Due to these risks, DERs with shorter lead times can offer real-option value (ROV) by delaying deployment until forecast uncertainty is smaller, effectively buying time for planners and reducing the probability of a mistake. While the value of real options can be significant, it is difficult to quantify without the requisite data, including historical loading data, historical forecasts, and current long-term project forecasts. These data needs are further elaborated on in the subsequent section.

Policy Considerations

The additional sources of value, including time value of money and real option value, associated with a transition towards integrated distribution planning that fully leverages DER deployments were explored above, but are not explicitly quantified due to the limited data publically available. Ongoing proceedings in California, such as the Distribution Resource Plan (DRPs) and Integrated Distributed Energy Resources (IDER), create important vehicles to share information between parties in order to explore these important but less conventional sources of value that are not yet well quantified.

V. Conclusion

In this report, we explored the capability of distributed energy resources to maximize ratepayer benefits while modernizing the grid. The opportunity associated with proactively leveraging DERs deployed over the next five years is significant, creating $1.4 billion a year by 2020 in net societal benefits across the state of California. Applying the state-wide methodology to a subset of real distribution capacity projects identified in California's most recent utility General Rate Case yielded similar results, suggesting DERs can cost effectively replace real-world planned distribution capacity projects today.

The impediments to capturing these benefits in practice remain significant. Utility incentives must be realigned to ensure that the full potential of DERs can be realized. Shifting the utility's core financial incentive from its current focus of "build more to profit more" towards a future state where the utility is financially indifferent between sourcing utility-owned and customer-driven solutions would neutralize bias in the utility decision making process. However, modernizing grid planning is also necessary. Grid planning must be updated to incorporate DERs into every aspect of grid planning, and the process itself must become radically more transparent with greater access to and standardization of data.

The benefits of achieving these changes would be real – and large. While initially complex to consider, the greater flexibility DERs can provide to grid planners and operators leads to greater reliability and resiliency. Similarly, the more targeted and incremental deployments of DERs can enable more efficient and affordable grids. Most importantly, utilities that can successfully modify planning processes would be able to fully take advantage of the assets their customers chose to adopt.

While no single report will adequately address all the issues – engineering, economic, regulatory – that naturally come with a transformative time in the industry, we hope that compiling these issues in one place, even with a high-level focus, advances the discussion and provides an overview of the critical topics for regulators and industry stakeholders to consider when evaluating the full potential of distributed energy resources.

About Grid Engineering Solutions

Our Grid Engineering Solutions team is leading efforts to make the 21st century's distributed grid a reality. At SolarCity, grid engineering is more than understanding how the current power system works and how to interconnect distributed energy resources. It encompasses a cross-functional approach to evaluating engineering, technology, economic, and policy considerations side-by-side. We apply our expertise in power systems engineering, energy economics, and advanced grid technology to unlock innovative solutions that enable the grid of the future.

The majority of the Grid Engineering Solutions team members, including the authors of this paper, are former utility engineers, economists, technologists, and policy analysts. We treat the design and operation of the electric grid as a major opportunity to partner across the energy industry, with the aim of driving innovation to benefit consumers and our environment. Collaboration across utilities, grid operators, regulators, national laboratories, philanthropists, environmentalists, distributed energy resource providers, energy service providers, and customers is paramount to meeting the challenge of modernizing our grid. We welcome any dialogue that helps foster the next generation of grid design and operations. For more information, please visit us at www.solarcity.com/gridx or contact us at gridx@solarcity.com.

Appendix 1: Overview of Traditional Avoided Cost Categories and Methodologies

The traditional avoided cost categories evaluated in this report are detailed in the following table. Descriptions of the avoided cost, overview of the CPUC Public Tool's treatment of these avoided costs, and TASC's adjusted methodologies are provided. The adjusted TASC methodologies are used to quantify the traditional avoided cost values used in this paper. See TASC NEM Successor Tariff filing for more details on quantification approach.[54]

AVOIDED COST	DESCRIPTION	CPUC PUBLIC TOOL METHODOLOGY	TASC INPUT
Energy + Losses	The value of wholesale energy that would otherwise be generated in the absence of DERs, adjusted for losses that would occur. In CA, the cost of carbon allowances from the Cap and Trade program is embedded in the wholesale energy value.	The Public Tool creates a forecast of future energy prices using a simplified dispatch model and applies those prices to the DER generation in each hour. The model also allows a locational multiplier to be applied to capture the additional value of DER generation that occurs in specific locations.	TASC used the default assumptions for calculating energy value, but utilized the locational multiplier with a value of 4.8%, which was the premium derived from the empirical correlation between DER locations and CAISO locational marginal prices (LMPs).
Generation Capacity	The value of avoiding the need for system generation capacity resources to meet peak load and planning reserve requirements.	The Public Tool calculates the long-run cost of capacity by determining the Cost of New Entry (CONE) for a combustion turbine, and nets that cost against the energy and ancillary services revenues that a plant would be expected to earn.	TASC used the default assumptions for net CONE, and assumed that the long-run marginal cost that net CONE represents is the value of capacity starting in 2017, also known as the Resource Balance Year (RBY).
Transmission Capacity	The value of avoiding the need to expand transmission capacity to meet peak loads.	The Public Tool allows the user to input a $/kW-year value for avoided transmission capacity. The model takes this input and assesses the avoided cost by taking into account the level of coincidence of DER generation with the coincident peak that drives transmission expansion.	TASC assumed the avoided cost was the marginal cost of transmission capacity, which was estimated to be $87/kW-year based on regression analysis of historical transmission costs and their correlation with load growth.
Distribution Capacity	The value of avoiding the need to expand distribution capacity to meet peak loads.	The avoided cost attributable to DERs takes into account the level of coincidence of DER generation with the drivers of these marginal costs, which are allocated to specific time periods by Peak Capacity Allocation Factors (PCAFs).	TASC assumed the avoided cost was the marginal cost of distribution capacity, which was sourced from each IOU's most recent CPUC general rate case.
Ancillary Services	The value of a reduced need for operational reserves based on load reduction through DERs.	The Public Tool defines the cost for ancillary services as a 1% of wholesale energy costs, and allocates the value based on hourly load.	TASC did not modify any assumptions with respect to how avoided ancillary services are calculated.
Renewable Energy Compliance	The value of reducing procurement requirements for renewable energy credits, due to reduced delivery of retail energy on which RPS compliance levels are based.	The Public Tool bases this value on the above market costs of RPS generation. Under a 33% RPS, each kWh of DER generation reduces the need for RPS generation by 0.33 kwh.	TASC assumed a 33% RPS by 2020 and did not modify any assumptions with respect to how avoided RPS costs are calculated.
Societal Benefits	The value of benefits that accrue to society, and are not costs directly avoided by the utility.	The Public Tool model provided the flexibility to insert assumptions for societal benefits based on $/tonne of emissions or $/kWh benefits.	TASC included the Environmental Protection Agency's value for the social cost of carbon, as well as estimates for NOx, PM10, land use, and water use benefits.

Appendix 2: Utility-Proposed Distribution Integration Investments in CA DRP

The following table presents the DER integration investment categories as identified in SCE's DRP filing. SCE's costs were scaled up to estimate total integration costs for all California utilities over 2016-2020. SCE cost estimates were stated at the category level, and were uniformly spread across the underlying investments. For each investment, applicability to DER integration is assessed using the threshold and screening questions identified in this paper. This quantification is necessarily high-level due to the lack of details provided, and additional details are necessary in order to fully evaluate investment plans.

INVESTMENT CATEGORY	INVESTMENTS	UTILITY COST CLAIM ($M)	APPLICABLE TO DERS (%)	RATIONALE
Distribution Automation	Automated switches w/enhanced telemetry	$355	0%	Business as usual: Automation programs are reliability driven and not necessary for DER integration.
	Remote fault indicators	$355	0%	Business as usual: fault indicators are reliability driven and not necessary for DER integration.
Substation Automation	Substation automation	$346	0%	Business as usual: Automation programs are reliability driven and not necessary for DER integration.
	Modern protection relays	$346	60%	Investment in protective relay upgrades can be valid at high penetration of DERs, although setting changes can frequently eliminate need for relay replacements.
Communication Systems	Field area network	$444	0%	Business as usual: supports preexisting utility efforts to extend SCADA visibility throughout distribution system.
	Fiber optic network	$444	0%	
Technology Platforms and Applications	Grid analytics platform	$119	33%	Investments in identification and communication of grid needs are valid for high DER penetrations. However, only some of these costs are applicable to DERs as these tools broadly support grid modernization and will be used to process data from smart meters and utilityi grid devices.
	Grid analytics applications	$119	33%	
	Long-term planning tool set	$119	50%	Long-term planning and distribution circuilt modeling tools are used to forecast all grid needs and scenarios, including reliablity, loads, and DERs; therefore, only a portion of these costs are driven by DER integration.
	Distribution circuit modeling tool	$119	50%	
	Interconnection application processing	$119	100%	Investments that support DER interconnection are directly related to DER integration.
	DRP data sharing portal	$119	100%	
	Grid and DER management system	$119	50%	Grid and DER management systems are used to manage all grid assets, including utility equipment and DERs; only a portion of these costs are driven by DER integration.
	System architecture and cyber security	$119	25%	As the grid becomes more reliant on more granular visibility and control, system architecture and cybersecurity investments are needed irrespective of DERs. Therefore, only a portion of these costs are driven by DER integration.
	Distribution Volt/VAR optimization	$119	25%	Business as usual: Volt/VAR Optimization programs preexisted DER deployments; while DERs increase Volt/VAR benefits, only a portion of these costs are driven by DERs.
Grid Reinforcement	Conductor upgrades to a larger size	$1,168	50%	Capacity and conductor upgrades driven primarily by safety, reliability and resiliency needs. However, capacity investments for high DER penetrations resulting in thermal limit violations are valid.
	Conversion of circuits to higher voltage	$1,168	10%	Business as usual: Supports preexisting utility efforts to convert circuits to higher voltage. Incremental costs associated with accelerated replacement could be driven by DER integration in some cases.
	Total	**$5,697**	**25% ($1,450)**	

Endnotes

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Note: SolarCity views the CPUC Public Tool as a useful resource to perform cost/benefit analyses, such as the analysis presented in this paper, in a transparent and publically repeatable manner. However, SolarCity cautions that there are structural flaws and limitations to the Public Tool that result in overstatement of PV and DER adoption and understatement of avoided cost benefits. Therefore, SolarCity does not support the use of the Public Tool in its current form to be the basis of ratemaking or tariff decisions.
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[44] This calculation reflects a 25-year useful life of assets and ratebase depreciation schedule with an authorized WACC of 7.8% and corporate tax rate of 42%. Property taxes are omitted. Project expenses are based on the O&M share of PG&E's 2014 distribution revenue requirement (41%), but revised down to a 30% ratio acknowledging that a portion of O&M is fixed O&M as opposed to variable O&M. CPUC Public Tool's default value for the societal discount rate of 5% is used to calculate societal net present cost.
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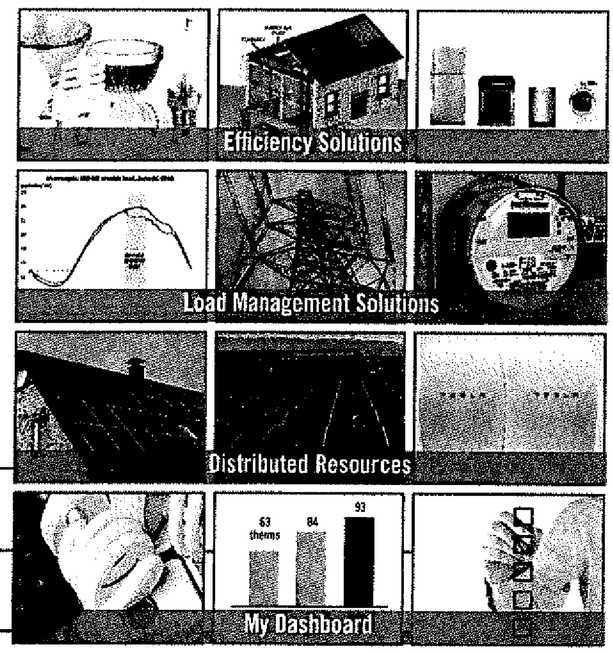
EXHIBIT 6

Ceres

Pathway to a 21st Century Electric Utility



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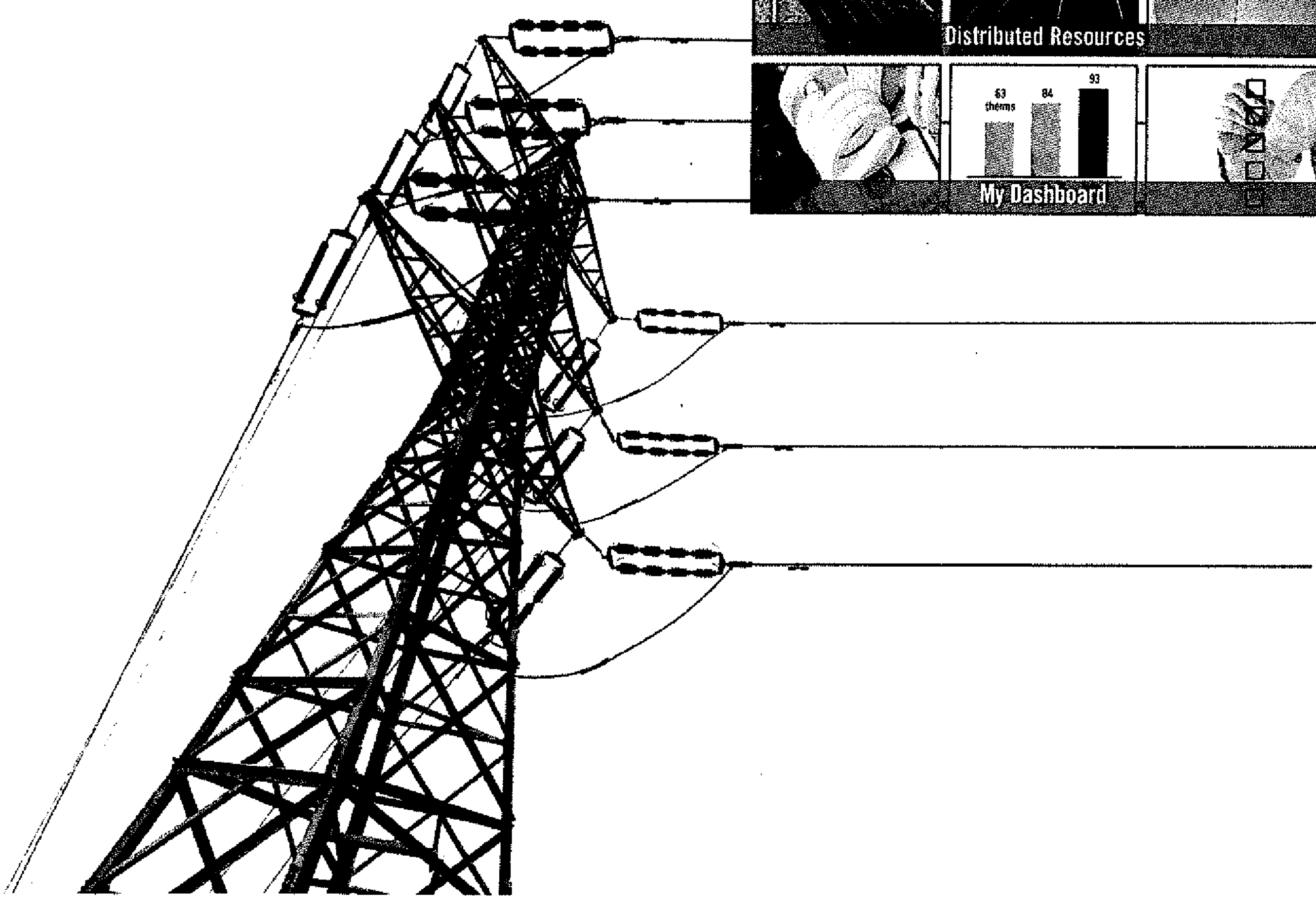

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About Ceres

Ceres is a nonprofit organization mobilizing business leadership on climate change, water scarcity and other global sustainability challenges. Ceres directs the Investor Network on Climate Risk (INCR), a network of more than 110 institutional investors with collective assets totaling more than $13 trillion. Ceres also directs BICEP, an advocacy coalition of 36 businesses committed to working with policy makers to pass meaningful energy and climate legislation. For more information, visit www.ceres.org or follow on Twitter: @CeresNews

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Peter is the Executive Director of Energy Infrastructure Advocates LLC, a strategic advisory consultancy focused on public policy supportive of utility and energy sector infrastructure development in a changing energy industry landscape.

Prior to the founding of EIA in 2012, Peter worked for over 30 years in investment banking, with a specialization in utility and power sector finance. Peter's banking experience includes capital markets advisory and transaction execution and strategic advisory services, including merger and acquisition and corporate finance advice. Peter's M&A experience includes all sectors of regulated utility and non-regulated power businesses. Throughout his career, Peter has been actively involved in outreach to regulators and policymakers, including work as an expert witness in regulatory proceedings and forums, presenting at industry and regulatory conferences on financial issues impacting utilities and power producers and in direct outreach on regulatory matters. In 2013, Peter authored a paper on Disruptive Challenges to the utility industry published by the EEI.

Peter's investment banking experience, includes prior experience at Macquarie Group, Bank of America, where he lead the Power and Utilities Corporate and Investment Banking effort, and Citigroup and Kidder Peabody, where he co-directed the Power & Utilities industry teams of each of those firms. Prior to investment banking, Peter worked for Arthur Andersen & Co.

Peter is a Director of the general partner of Enable Midstream Partners, LP, a midstream energy services provider and a Director of NextEra Energy Partners GP, an owner of renewable power generation. Peter is also a Director of Southwest Water Company, an infrastructure fund owned water and wastewater utility.

Peter holds an MBA in Finance from New York University and BBA in Accounting from Iona College. Peter practiced as a Certified Public Accountant until 1981. During 2008 to 2011, Peter was Co-Chairman of EEI's Wall Street Advisory Group.

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Pathway to a 21st Century Electric Utility

Commissioned By: Ceres
Authored By: Peter Kind

As a banker serving the U.S. utility industry for over 30 years, I have long questioned the impact of policy actions and regulatory mandates that threaten the revenue base of utilities and the industry's financial health. In 2013, I authored "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Energy Business," published by the Edison Electric Institute (EEI). That paper presented my views, looking through the lens of an investor, of the challenges confronting the long-term financial viability of the electric utility industry given its present business model.

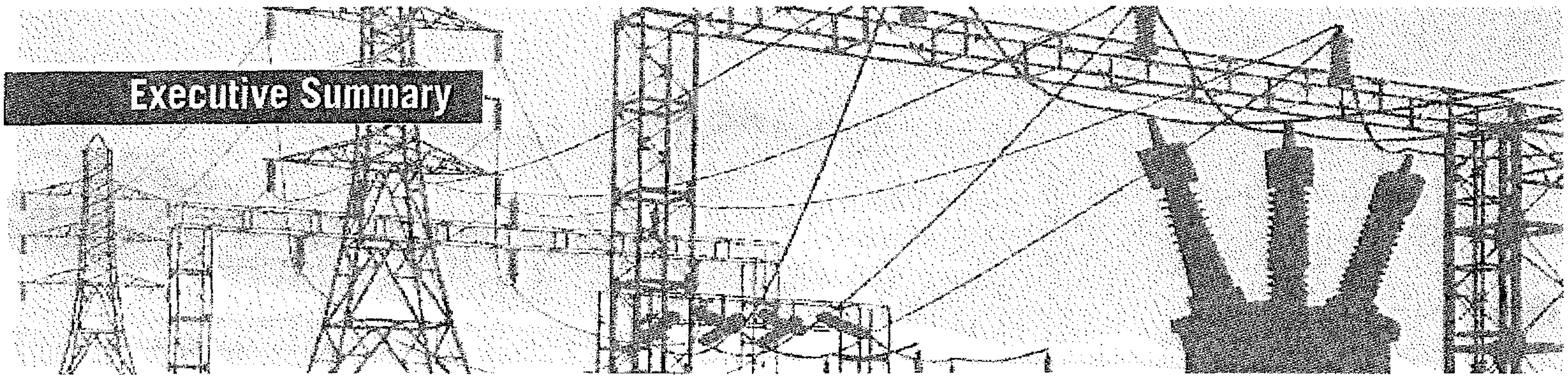
Since the release of *"Disruptive Challenges,"* the forces outlined therein have continued to develop, particularly the pace of technological innovation and cost-curve improvements. Importantly, electric customers and the policy community have continued to foster key disruptive forces by confirming their support for customer energy supply choice, net energy metering and opposition to increased fixed utility charges. My positions have evolved in order to find solutions that can promote collaboration and alignment of interests.

In reviewing the constantly evolving landscape, I felt that it was important to provide an updated, more holistic perspective that aligns society's needs with the interests of utilities and their customers. In 2010, Ceres made an important contribution to the dialogue with the release of *"The 21st Century Electric Utility: Positioning for a Low-Carbon Future,"* and it seemed a natural fit to collaborate with Ceres on this new paper.

Utilities do an excellent job of what they are mandated to do—provide safe, reliable and affordable energy. Utilities are not going away, because we require them to operate the electric grid, so why not expand the scope of their mandate to manage an environment in which consumers use energy and electricity more efficiently to create customer value and optimize the electricity system for the benefit of all? In this environment, utilities will be incented to maximize customer and system value, as opposed to simply building infrastructure.

Utilities are not going away, because we require them to operate the electric grid, so why not expand the scope of their mandate to manage an environment in which consumers use energy and electricity more efficiently to create customer value and optimize the electricity system for the benefit of all?

Given the importance of revising the utility industry model for the benefit of customers, society and utility investors, this paper is an expression of my evolved views in an effort to find common ground that will support a robust 21st Century Utility model.



Challenges Facing the Electric Utility Business Model

Over the past decade, a confluence of challenges facing the electric utility business model has stimulated active discussion among utility industry stakeholders. The challenges are the result of economic, demographic, behavioral, policy and technology trends, and are not expected to reverse. In fact, they are continuing to gain momentum, particularly the development of new technologies, continued reductions in renewable energy costs, and policymaker support for a revised vision of utility service that supports customer choice.

Utility sector investments, however, continue to trade close to all-time high valuations based on low interest rates. Threats to the utility sector are still in the early stages because customer adoption of new energy technologies remains low, but are growing. Furthermore, customers, rather than investors, are bearing the near-term cost of disruption through increased utility rates, somewhat offset by lower fuel costs.

Once investors begin to experience these challenges as a direct impact on the economic-return potential of their investments, however, the cost and availability of capital to fund the utility sector will suffer. Given that the industry relies on 30-plus-year investment recovery cycles, it is essential that capital deployed today be planned and rationalized to avoid future stranded costs, or investments that are no longer economical.

The current 100-year-old utility business model does an excellent job of keeping the lights on, but it often does not align interests and behaviors or facilitate the policy goals and customer dynamics that exist in 2015. To create the clean, efficient and sustainable energy future that all stakeholders seek, we must revisit the industry model to ensure alignment with customer and policy goals, while also ensuring that utilities and third-party providers are properly motivated to support their customer, societal and fiduciary obligations.

The current 100-year-old utility business model does an excellent job of keeping the lights on, but it often does not align interests and behaviors or facilitate the policy goals and customer dynamics that exist in 2015.

Policy and industry stakeholders in most states are neither proactively addressing industry model challenges from a comprehensive policy perspective, nor seeking the collaboration of all stakeholders to find a solution that benefits all parties. In New York, a closely watched initiative has policymakers defining a future in which the utility role involves managing the grid and acting as a platform provider for third parties. This role is not as investor friendly as utilities would desire. In many states, despite customer and policy opposition, electric utilities are proposing increases in fixed charges, which discourage energy efficiency and impact low-income customers. This lack of progress in stakeholder collaboration is ***not*** in our collective best interests.

While the cost structure of electric distribution utilities is predominantly of a fixed nature (i.e., not meaningfully impacted by volumes or operating variability), utility rate structures have typically authorized a small fixed-charge component. Pursuing an increase to fixed-charge recoveries is a tariff design tool that utilities have actively pursued since 2013 to mitigate revenue risk from the challenges they face.

However, there has been meaningful opposition on the part of customer interests and policymakers to utility proposals to significantly increase fixed charges. The policy of adopting monthly fixed-charge increases has several flaws—principally that such increases would remove the price signals needed to encourage energy efficiency and efficient resource deployment—that need to be considered when assessing alternatives through a lens by which all principal stakeholders benefit. This paper proposes several solutions to address the utility revenue challenge as an alternative to increased fixed charges, such as inclining block rates, reforming net energy metering, use of bidirectional meters, time-of-use rates, accountability incentives and identifying new revenue opportunities for utilities.

More broadly, this paper proposes a **new pathway to a 21st Century Electric Utility system** that creates benefits for customers, policymakers, utility capital providers and competitive service providers.

> **This paper proposes several solutions to address the utility revenue challenge as an alternative to increased fixed charges, such as inclining block rates, reforming net energy metering, use of bidirectional meters, time-of-use rates, accountability incentives and identifying new revenue opportunities for utilities.**

The key differentiators proposed in the pathway toward a new utility model are as follows:

a) engage the distribution utility to be at the center of integrating resources and stakeholder collaboration to achieve customer and policy objectives through accountability and incentives;

b) shift regulatory oversight to focus on integrated distribution system planning and development of transparent accountability metrics;

c) ensure that utility revenues will reflect incentives (or penalties) earned for accountability of results and new energy management services sourced through new resources, such as an energy management applications store; and

d) pursue cost-effective planning to identify the most efficient technologies to be employed, and cap customer incentives based on the most economical alternatives to achieve policy goals.

The paper first sets the stage by identifying the stakeholders and potential participants in a new industry model, summarizing the objectives and considerations of stakeholders, and reviewing the debate that is playing out, including actions by several of the more proactive states. It then lays out a vision for the 21st Century Utility and identifies foundational principles to support this vision before proposing the pathway. Given that we have over 50 states and districts that regulate our utilities, there will be no one-size-fits-all solution.

The **vision** proposed for the 21st Century Utility model is relatively straightforward, and includes:

- enhanced reliability and resilience of the electric grid while retaining affordability;
- an increase in cleaner energy to protect our environment and global strategic interests;
- optimized system energy loads and electric-system efficiency to enhance cost efficiency and sustainability; and
- a focus on customer value, including service choices and ease of adoption.

Instead of maintaining our current policies, which encourage increased electric consumption and capital investments, the objective of the vision is to develop a model that enables customer value and service and achieves policy objectives to position us for the certainties of the future—particularly that the current concentration of fossil fuels in our energy mix poses significant risks to our economy and environment.

Because there is no reasonable threat over the foreseeable future of significant customer grid defection, a robust electric grid is a key component of a 21st Century Electric Utility, and thus, financially healthy utilities will be essential to maintaining and operating the grid.

The **foundational principles** or ground rules to support the achievement of this vision are as follows:

- financially viable utilities are essential to fund and support an enhanced electric grid;
- policymakers must promote clear policy goals as part of a comprehensive, integrated jurisdictional energy policy or 21st Century Utility model;
- commitment to engaging and empowering customers can help them make intelligent energy choices, including third-party engagement and access to necessary data; and
- equitable tariff structures promote fairness and policy goals.

The **pathway** proposed is one wherein policymakers task utilities with the **responsibility for** being at the center of coordinating and accelerating the refinement of our model for a 21st Century Electric Utility, and holds them accountable with penalties and incentives. On this pathway, policymakers will collaborate with stakeholders to develop and authorize the vision for the industry's future for customers and providers. Policymakers will then outline a comprehensive plan to realize their 21st Century Electric Utility model. The proposed pathway shifts regulatory oversight from being administered primarily through periodic rate cases to a forward-looking focus on planning, accountability and financial incentives for results achieved. Tariffs will be refined to address fairness, policy goals and provide price signals, consistent with enhancing system wide efficiency and environmental protection.

Regulators will create incentives and penalties to encourage and hold utilities accountable for achieving transparent goals and metrics to be outlined for measuring progress and success. **Technology innovators and third-party service providers** will collaborate with customers and utilities to create and refine products and services that support policy goals, engage customer interest and integrate efficiently with the grid. **Utilities** will partner with third-party providers and customers to provide reliable, affordable, clean energy in the most efficient way possible. **Customers** will be educated as to opportunities to deploy new services to enhance the value of their electric service and achieve societal benefits, such as reducing their environmental footprint.

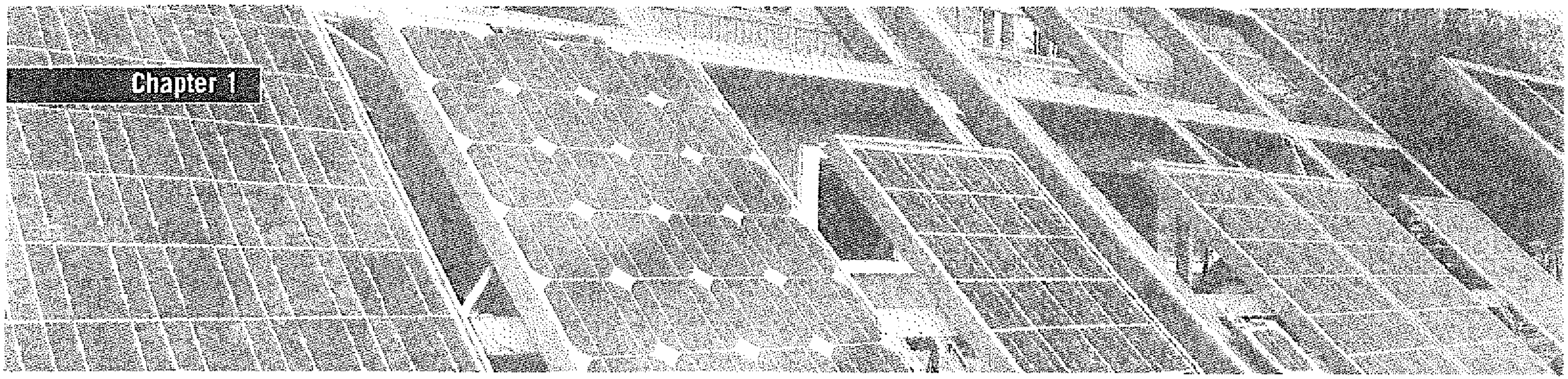
Energy efficiency and system optimization, for example, have been an area of focus since the 1980s, and while progress has been made, the majority of customers have not taken advantage of the opportunities that can be realized. The American Council for an Efficient Energy Economy (ACEEE) estimates that a 40 to 60 percent reduction of electricity sales could be achieved by 2050 by harnessing the full suite of opportunities. On a pathway to a 21st Century Utility, we must redouble our efforts to achieve these savings by increasing customer education and giving utilities incentives to engage their customers in adopting such technologies. Because increased efficiency strikes at the revenue base of utilities, the proper incentives must be adopted so that utilities will be at least indifferent to the loss in electricity sales and ideally, be motivated to encourage energy efficiency.

In order to realize the societal benefits of a clean and efficient electric industry, each state should move forward now on a pathway to a 21st Century Utility model. Each state will have different challenges to confront, but the goal would be to develop several robust models that can be tested, compared and refined over time.

The Environmental Protection Agency's newly released **Clean Power Plan (CPP)** provides an excellent opportunity for states to consider their utility model as a component of their CPP compliance plan filings. The CPP sets standards for reducing greenhouse gas emissions from existing and new power plants, and calls for each state to provide its compliance plan by September 2016. The CPP will enable each state to reconsider its energy future and align state compliance plans with a pathway to a 21st Century Utility. Longer-term, customers, society and utility investors will benefit from proactive solutions.

Utilities have remained committed to their historical obligation to provide customers with safe, reliable and affordable service. As dynamics have evolved, society now expects that utilities will confront new priorities, such as protecting our environment and assisting customers in being more efficient with their energy usage. These new priorities challenge utilities' revenue and profitability levels and, thus, utility fiduciary obligations to their investors. A new industry model will need to provide opportunities for utilities to earn a reasonable return while providing society and customers the services they seek.

The proposed pathway shifts regulatory oversight from being administered primarily through periodic rate cases to a forward-looking focus on planning, accountability and financial incentives for results achieved.



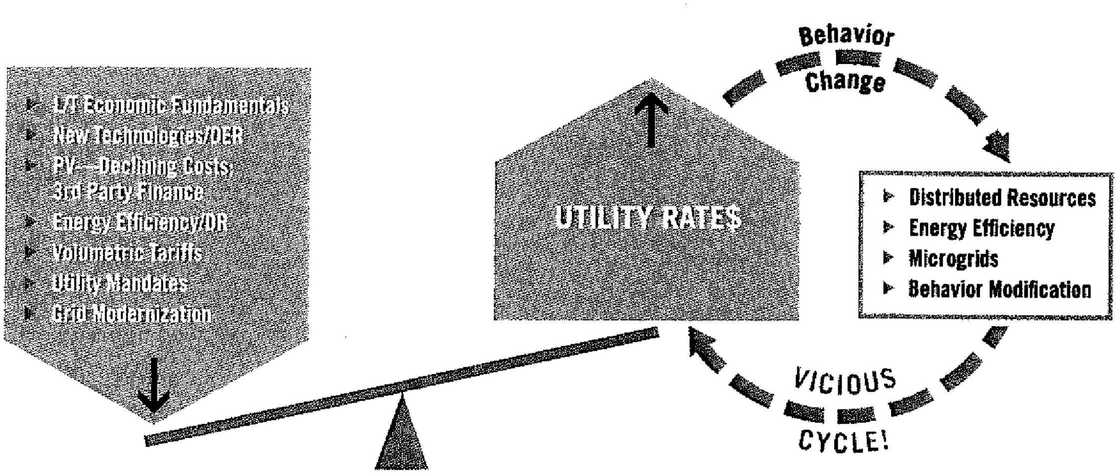
The Case for a 21st Century Electric Utility Model

Disruptive Forces—A Quick Review

Over the past several years there has been active discussion among utility industry stakeholders as to the confluence of challenges facing the industry business model. These challenges are considered long-term forces that are not expected to be reversed, and they encompass economic, demographic, behavioral, policy and technology trends. The principal challenges facing the utility model can be summarized as follows:

- slowing demographic (U.S. population) and economic growth opportunities have reduced electric consumption growth and customers' disposable income levels;
- customer interest in reducing energy usage and environmental impact has gained attention and interest, particularly among Millennials;
- public-policy goals seek to increase energy-efficiency adoption and clean-energy production and to reduce environmental emissions;
- price inflation and costs to deploy new grid technologies are increasing utility capital budgets and requiring increased electric rates (although rate increases have not in general outpaced inflation);
- customers now have enhanced options to save on their energy bills through programs that reward adoption of clean technologies (e.g., solar distributed energy resources combined with net energy metering programs); and
- U.S. regulatory models that are energy-usage based, regardless of load or time of day, constrain prospects for utility revenues and financial health.

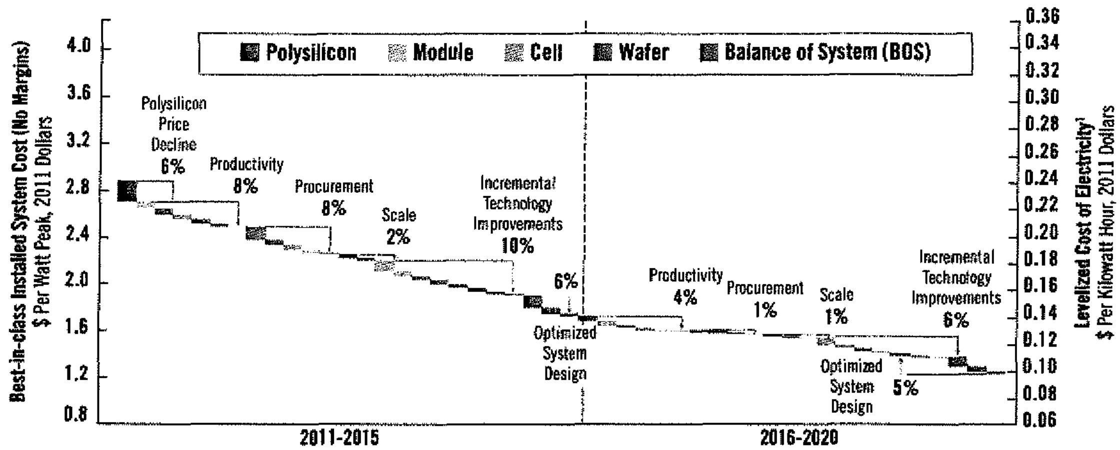
Figure 1: Disruptive Forces—Impact and Feeding of the Vicious Cycle



A confluence of factors are posing disruptive threats to the traditional utility business model.

All of these dynamics are at play while distributed energy resource (DER) economics continue to improve, due to improved technology, market competition and the advent of attractive customer financing options (see **Figures 2 and 3**, below). Left unattended, these challenges encourage a vicious cycle in which customers are motivated to self-generate (such as by rooftop solar) to avoid increasing utility prices, thereby leaving the cost to fund the electric grid to an increasingly smaller group of customers. And yet the grid is essential for DER technologies, particularly rooftop solar, because it allows customers to sell their surplus energy back to the utility. A 2013 study commissioned by the California Public Utilities Commission found, in fact, that due to net energy metering, residential DER customers in California paid approximately 50 percent less toward the fixed cost of providing utility service.[1]

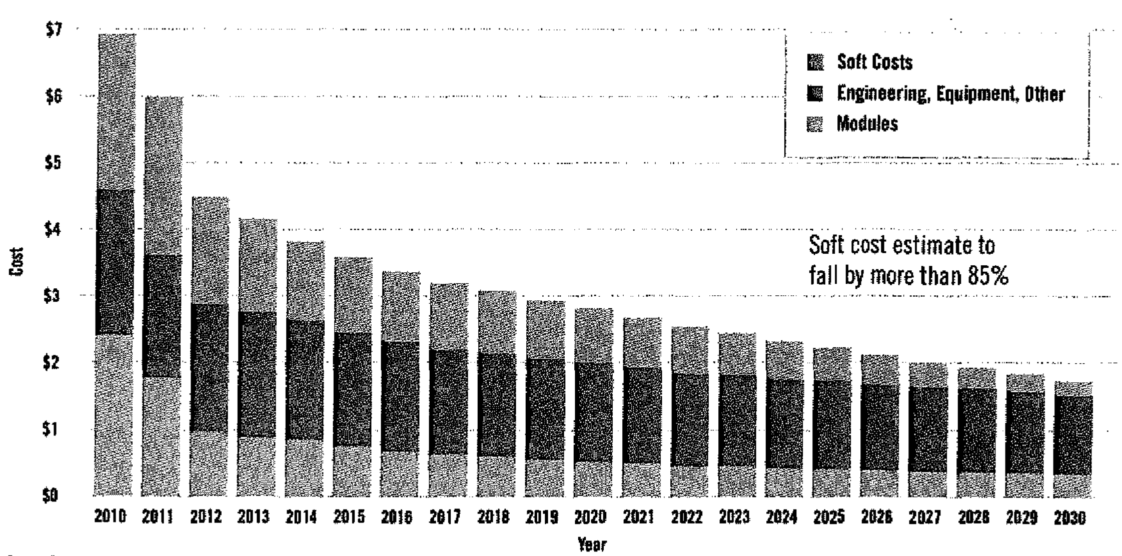
Figure 2: PV Cost Improvements—Innovation and Scale Drive Opportunities



1 Levelized cost of energy; assumptions: 7% weighted average cost of capital, annual operations and maintenance equivalent to 1% of system cost, 0.9% degradation per year, constant 2011 dollars, 15% margin at module level (engineering, procurement, and construction margin included in BOS costs).

Source: McKinsey & Company.

Figure 3: Average USA Price Per Watt for a New Solar System



Source: Bloomberg New Energy Finance.

1 Energy and Environmental Economics, Inc., "California Net Energy Metering Ratepayer Impacts Evaluation," Prepared for the California Public Utilities Commission, October 2013.

Clearly, the electric grid will continue to be essential to virtually all customers for the foreseeable future. In fact, the viable solar rooftop market—after factoring in home ownership, credit scores, locational positioning and suitability and NEM favorability—is currently projected to be approximately 20 percent of US households.[2] Thus, utilities must retain their financial viability to attract the capital required to support the grid. Most investors are not focused on these issues today due to low, though increasing, penetration of DERs and allowed cost recovery of "lost revenues" in future rate cases.

Other disrupted industries have reached the tipping point at which new products and services attain a penetration level and trajectory that challenge the viability of an old-line business and its access to capital. At that point in those challenged industries, financial access and viability are forever threatened. Kodak and Polaroid are prime examples of how disruptive forces (primarily technology in those cases) can destroy a company's financial value and capital access. Given the essential nature of utility services, however, a death spiral for the electric utility industry is not expected in the foreseeable future. Stakeholders must nevertheless be proactive to protect utilities' financial viability, given the industry's vital importance to our energy future.

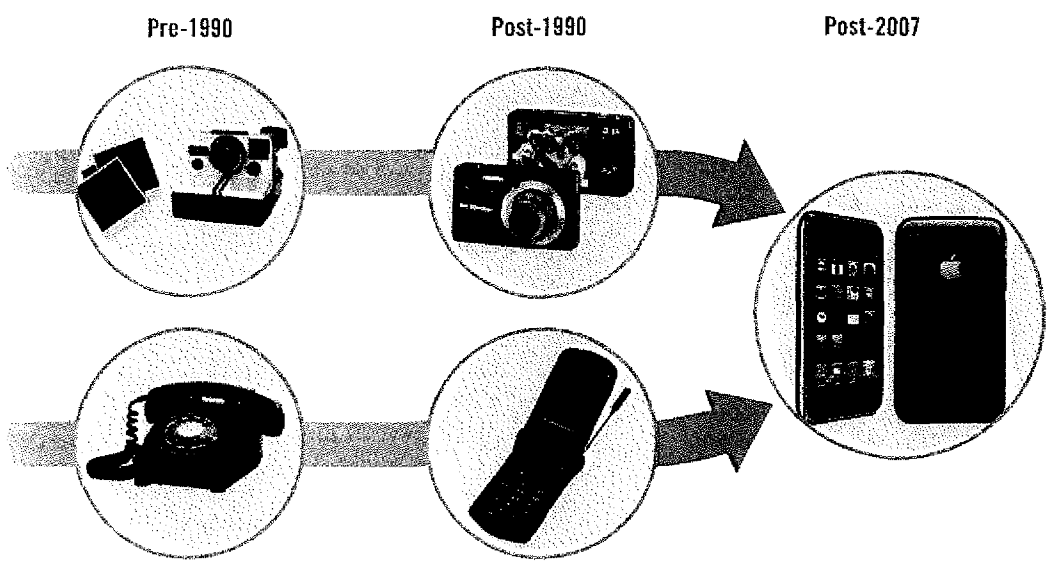
Other disrupted industries have reached the tipping point at which new products and services attain a penetration level and trajectory that challenge the viability of an old-line business and its access to capital.

Value and Future of the Electric Grid

While the "Disruptive Challenges" paper and others have drawn parallels between landline telephone deregulation and the electric utility model, there are important distinctions between the two. First, there is no known technology today by which electricity can be transported from location to location without a wire. Second, for many customers, installing the technology to disconnect from the grid would be prohibitively expensive, and/or they are not in the proper location or lack the ownership control (i.e., rent their homes) to deploy current DER technologies. In addition, industry experts believe there is great societal value created from the development of a robust grid and that grid defection creates barriers to enhancing and maintaining the electric system we require.

While industry discussion, including "Disruptive Challenges," gives examples of a scenario whereby certain customers could disconnect their access to the grid, or new construction could be grid independent (e.g., DER customers with storage), there is no reasonable scenario for **significant** customer exit from the grid for the foreseeable future. The only way to sell power back to the grid is to be connected to the grid. For DER customers, as an example, every time a new

Figure 4: Examples of Technology Disrupting Main Line Industries



2 GTM Research and Vox

customer installs rooftop solar, he or she is likely basing that economic decision on the ability to sell surplus renewable power back to the grid for at least 20 years.

The grid acts to enable the benefits of distributed resources through the sale of electricity to others and to enable commercial opportunities and transactions through the powering of our entire economy. In addition, the grid provides needed backup support for DERs and storage when renewable resources are not functioning or when demand exceeds system capacity. Thus, the electric grid is, and is expected to remain, the backbone of our electric energy system.

A robust electric grid is therefore required to achieve the greater reliability sought by all customers and to enhance access to additional bidirectional power inputs for DER customers. A study by Brattle Group, commissioned by the EEI in 2009, projected that the U.S. electric utility industry will need to invest between $1.5 and $2 trillion between 2010 and 2030 to maintain current levels of reliable electric supply.[3] To maintain a robust, responsive and resilient grid, we must have a structure in place that supports financially healthy utilities capable of attracting the significant capital required. Thus, the question of structuring tariffs to support the grid and other valuable services provided by utilities must be considered (see **Ratemaking and Tariff Design**, page 29).

The Stakeholders in a 21st Century Electric Utility Sector

It is critical that any attempt to develop 21st century approaches seek as much alignment as possible among the key stakeholders involved in electric utility planning. The stakeholders in electric utility debates continue to evolve as priorities and key issues are refined or emerge, and today include residential, commercial and industrial customers, technology sector providers, utilities and their shareholders.

Residential Customers

Residential customers continue to have significant clout in the evolution of policy due to their voting power and large numbers. Groups representing low-income residents and seniors (who often live on a fixed income) tend to have influence because service cost is a high priority. Another prominent voice in the residential class debate is environmental advocacy groups that seek a focus on environmental stewardship and sustainability. Between these groups, there is alignment that aims to avoid high fixed charges for utility services and supports well-designed inclining block rates. Inclining block rates aid low-income residents and seniors by creating a progressive rate tariff: the more you use, the more you pay per unit. From an environmental policy perspective, inclining block rates provide an incentive to conserve energy usage by charging higher rates to the higher energy users.

Commercial and Industrial Customers

Although large commercial and industrial customers lack voting clout, they are active voices in the development of energy policy. Policymakers need to be aware of large customers' impact on the economic growth and vitality of a region; low utility rates will retain and attract them. While energy prices and availability are not the only factors in the drive for corporate competitiveness, large businesses can relocate when the local policy environment does not support their competitive position. In addition, large commercial and industrial customers (including General Electric, Procter & Gamble, Microsoft, Coca Cola and Walmart) are increasingly focusing on their sustainability profiles, including procurement of renewable energy. Thus, as stakeholders consider how to retain current business customers and develop and attract new industries, energy prices, reliability and access to clean energy will be key factors.

Policymakers

Policymakers and regulators tend to be attuned to their most vocal customers, because their voting power controls the ongoing "seat" of the policymakers. It is clear from the wide array of state-mandated renewable portfolio standards, energy-efficiency programs, net energy metering tariffs, and inclining block rates that policymakers are focused on clean energy, consumer choice, efficiency and price signaling. One question this paper seeks to address is whether policymakers are doing all they reasonably can to accelerate programs to optimize these objectives.

Technology Sector Participants

A recent entrant into the energy policy debate is technology sector participants, particularly renewable-energy providers. These entities are selling their products to customers directly and, as a result, customers use less electric service from the utility. While many of these providers understand that they need to cooperate with utilities to provide customers the benefit of their product offering, there is typically no clear, approved path for these competitive providers to partner with utilities to promote their offerings in a way that benefits both the technology provider and the utility. The interaction between technology and utility providers is often adversarial, with the technology provider seeking to sell products that will limit electric sales and thus adversely impact utility revenues. Utilities have therefore been hesitant to partner

3 Brattle Group. ","In Transforming America's Power Industry, The Investment Challenge 2010–2030." (2009).

with these third-party providers, which have built strong policy advocacy efforts and industry organizations because such activities are essential to their future viability.

Utilities and Their Investors

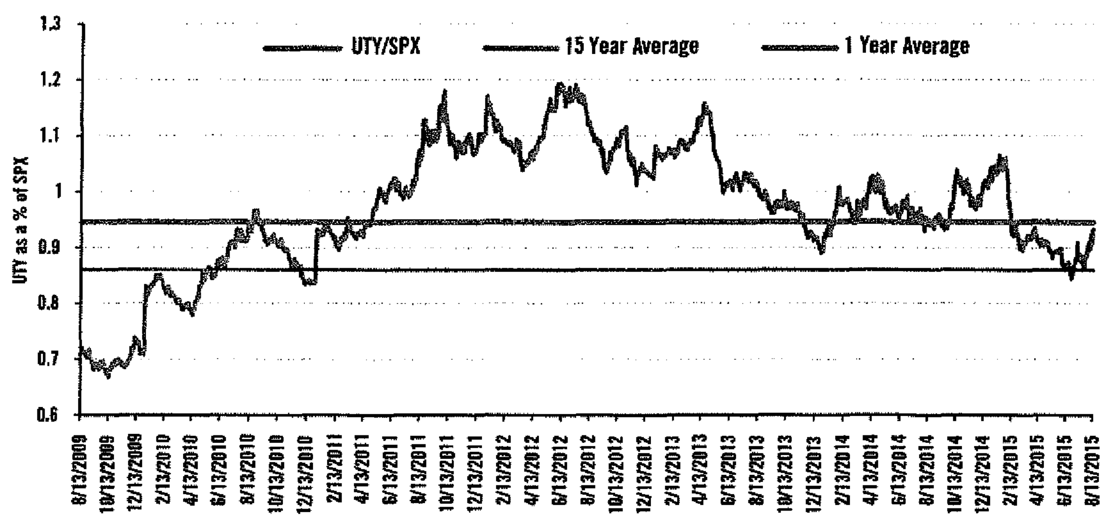
Utilities have many masters, but their principal obligations are to provide safe, clean, reliable and affordable electric service to customers and to earn a fair return on capital invested. Electric utilities generally do an excellent job of meeting customer-service expectations. A comprehensive study, "Exploring the Reliability of U.S. Electric Utilities," showed that reliability, despite extreme weather events, averages above 99.9 percent.[4] However, extreme weather events, such as hurricanes Katrina (2005), Irene (2011) and Sandy (2012) and devastating tornadoes such as Joplin (2011) are examples of the need for enhanced electric grid "hardening" and resilience to protect our citizens and economy.

Achieving an adequate return on capital, in particular in the short term, depends upon selling more energy, because that is how tariffs tend to be structured. Utility boards of directors typically structure utility management compensation programs based on achieving reliability factors and a larger weighting to financial returns. This is more customer friendly than other industries, in which executive compensation is based solely on market share and profit goals. While 25 states offer incentives for efficiency results,[5] these programs tend to offer limited financial incentives to utilities for promoting energy-efficiency services or clean technologies.

For example, while California has been proactive in providing incentives to utilities for encouraging energy efficiency, the incentives reported in 2014 were less than 1.25 percent of pre-tax operating income for the largest California utilities, or less than 0.1 percent in additional return on equity (ROE), after tax. Locating the disclosure of earned incentives in the California utilities' SEC filings is like finding a needle in a haystack. That makes it hard for investors to reflect in their valuation assessment a material, recurring, transparent and timely (in California there is a several-year lag in calculation) incentive mechanism. **While incentives should align behaviors, insignificant and nontransparent levels of incentives will not drive behavioral change and realization of optimal results.**

While utilities are interested in and impacted by the debate on regulatory models, their interactions are challenged by a skeptical policymaker environment, which often presumes that any position by an electric utility reflects a self-serving benefit. Thus, utilities are in a challenging position when it comes to leading or proposing solutions. As a result, utilities tend to be defensive in their approach and often lack the vision or motivation to identify areas where the business model can be enhanced for the benefit of their customers and investors. Instead of arguing for incentive mechanisms, many utilities have been seeking to increase fixed charges, while customers and policymakers are vehemently opposed to such action. An evolved approach would focus on common ground with win4 (i.e. beneficial to customers, policy, competitive providers and utilities) opportunities.

Figure 5: Utilities Are Valued Above 15-year Averages and Comparable to S&P 500

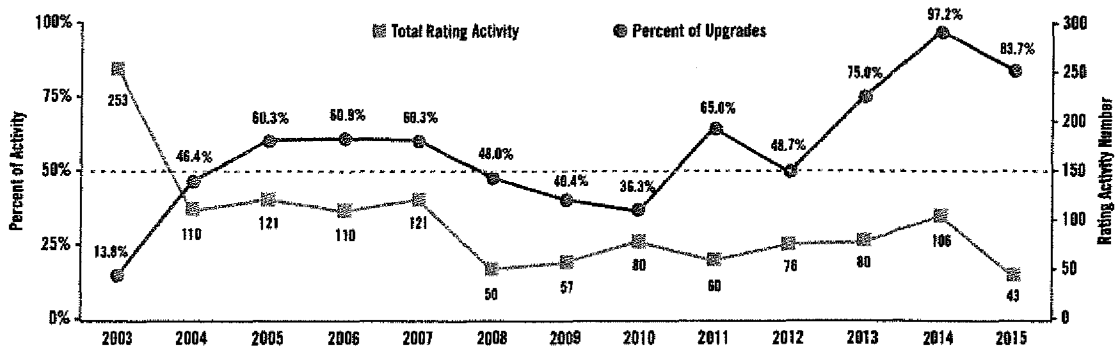


Source: BofA Merrill Lynch Global Research, Bloomberg

4 Larsen, Sweeney, LaCommare and Eto, "Exploring the Reliability of U.S. Electric Utilities," (2012).

5 ACEEE Economy, "Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency," June 2015.

Figure 6: Credit Rating Agency Actions Suggest Improving Credit Quality



Source: Edison Electric Institute, Fitch Ratings, Moody's, Standard & Poor's

Utility investors as a group are not interested in change, because the results they have realized from their investments in the sector have provided stable returns. Investors fear that any change could lead to an adverse impact on short-term results and that the defensive investment attributes they have sought—low price volatility, stable economic returns and cash dividend yields—may be compromised. As stated above, boards have structured the bulk of utility management compensation on achieving profit objectives, in addition to reliability performance. Investors are generally comfortable with the transparency of the utility model, despite the argument that the industry model may no longer be appropriate or viable in a changing environment. In fact, utility stock prices today are near all-time highs on a price and valuation multiples basis. Current valuation metric levels (See **Figure 5**) suggest that investors continue to view utilities as an attractive place to deploy capital.

If a material change in business financial performance were to be realized, investors would likely become less sanguine about deploying capital in the sector. But the majority of utility-sector investment analysts and rating agencies see little to be concerned about as long as the penetration rate of efficiency and clean-energy resources is low and regulators allow utilities to recover lost revenues in the near future. In fact, utility credit ratings have solidified over the past several years, particularly distribution utilities, as the economy has stabilized and industry restructuring volatility from the 2000 - 2005 era has been resolved. (See **Figure 6)** So, while short-term dynamics are the current focal point of the investment community, longer-term dynamics should be a key consideration in order to avoid disruption to the utility industry, its customers and our economy.

So, while short-term dynamics are the current focal point of the investment community, longer-term dynamics should be a key consideration in order to avoid disruption to the utility industry, its customers and our economy.

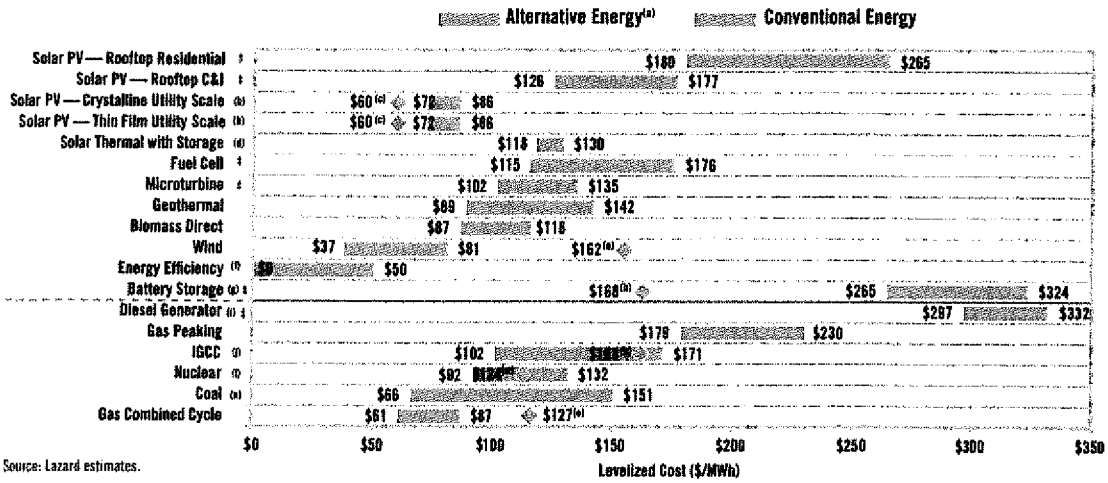
Utility investors, individually or as a group, are not often at the table in discussions on energy policy. Many institutional investors prefer the current utility business model and deal with change by selling the sector or certain investments when it starts to evolve in a way that appears more risky. While some investors, such as those in the $13 trillion Investor Network on Climate Risk (INCR) have become involved in clean-energy policy advocacy, it is still rare to see major institutional investors show up to address a state regulatory policy issue or to support a utility rate case.

Key Stakeholder Issues

Although unanimous agreement on the objectives for a 21st century electric utility industry model is not likely to be achieved, there appears to be solid customer, policymaker and utility support for key foundational objectives for the future industry. Key objectives include improved reliability and resilience of electric service, a cleaner sustainable electric supply and customer cost stability.

Customer cost stability is difficult to achieve in a regulatory construct that seeks (i) usage-based pricing, (ii) customer choice for self-generation of electric supply, compensated by non-DER customers, and (iii) limits on utilities' ability to serve and earn revenues from new 21st Century Utility services. Moreover, the investment required to harden the grid to improve reliability and resilience and provide a cleaner mix of energy resources will increase the cost of

Figure 7: Unsubsidized Levelized Cost of Energy Comparison—September 2017



Source: Lazard estimates.

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under some scenarios; such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of certain conventional generation technologies, etc.) or reliability-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy generation technologies). Diamonds typically represent expected cost in 2017, wind is for offshore, for more information see https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf

providing service. Despite improving economics, the cost of clean energy, excluding externalities, will likely be more expensive than the current embedded cost of existing generation, because investment and backup capacity are required to support renewable supplies, which are intermittent. Given current utility pricing policies that do not consider externalities, the cost of electric service is expected to increase over time. However, as shown in **Figure 7**, clean energy is expected to become increasingly competitive with traditional fossil energy sources, even before considering carbon costs.

One of the key disputes in the discussion of a 21st Century Utility is the value of clean energy resources. Currently, neither the cost of carbon nor the system wide benefits of a clean-energy strategy, such as reduced system losses and transmission needs, are fully factored into the price of electric power. When the cost of carbon and other externalities are reflected in the cost of energy, the cost to customers will likely prove the long-term benefit of a clean-energy strategy. With the appropriate policies and alignment of interests, the value of electric service can be enhanced. For instance, optimizing our system and the use of energy can reduce the need for new peaking capacity and related incremental infrastructure.

Additional objectives, of policymakers and engaged customers, include system and energy-efficiency optimization, price signals to encourage economic efficiency and optimization, and regional economic growth. But without encouraging efficiency (via technology, price signals and targeted incentives) it will be quite difficult to optimize the primary objective of enhanced price stability, given that incremental resources and investment would be required to support incremental consumption.

J.D. Power, a leading global market-research firm, evaluates industries to understand what drives customer interests, loyalty and retention. In J.D. Power's recent rankings of utility customers, their analysis prioritizes customer attributes as follows:

	Customers	
	Residential[6]	Business[7]
Power Quality and Reliability	1	1
Price	2	4
Billing and Payment	3	2
Corporate Citizenship	4	3
Communications	5	5
Customer Service	6	6

Residential customers are primarily focused on power quality, reliability and price. Interest in new technologies and environmental stewardship does not reflect separate categories but rather contributing factors in the price and

6 J.D. Power and Associates, 2015 Electric Utility Residential Satisfaction Survey.

7 J.D. Power and Associates, 2015 Electric Utility Business Customer Satisfaction Survey.

corporate citizenship scores. Industry data show that a relatively low percentage (less than 1 percent nationally)[8] of utility customers are currently seeking new technologies and choosing to self-generate from renewables. Customers' primary focus today is on reliability and price. A much smaller subset of customers are **proactive** in initiating the adoption of energy-efficiency and clean-energy technologies, but it is a group that is growing rapidly and is expected to increase dramatically in the coming years.

Energy Efficiency—A Growing Opportunity

One of the most significant opportunities to enhance both customer value and environmental benefit is the expansion of energy efficiency. Presently, however, customer adoption rates are low. Policy frameworks need to develop incentives for overcoming the barriers to adoption.

> **The opportunity to increase energy efficiency is substantial, but will require the focus of stakeholders to overcome the barriers to adoption.**

A study by the Edison Foundation on the impacts of energy efficiency at a national level shows that energy efficiency is increasing, but amounted to only 3.4 percent of total 2012 electric energy sales.[9] Another study prepared for the Edison Foundation found that when energy-efficiency savings are combined with enhanced building codes and standards, such savings will increase by 2035 from current levels to 5.6 percent of total electric energy use.[10] While any increase in the adoption of energy-efficiency tools is a positive development, economic studies indicate that much more is achievable and would benefit both customers and the environment.

Leading factors in the low adoption rates for energy efficiency include a lack of general awareness of opportunities (particularly because customers cannot price-shop for another utility provider), lack of trust in third-party providers (due to ongoing "junk" mailings and cold calling), the cost to implement new technologies or services when up-front investment is required, and the fact that customers are too busy to learn about opportunities that may be consistent with their long-term economic and environmental interests.

A recent study by the ACEEE, for example, found that energy-efficiency opportunities could reduce electric sales by 40 to 60 percent from current 2030 forecasts, based on intelligent efficiency advances, zero-net-energy building standards and improved efficiency of appliances and technology. The study also noted significant progress in the energy intensity of our economy from 1980 to 2014 due to structural changes (e.g., the reduction of our manufacturing base) and improved efficiency of appliances, new buildings and electric infrastructure.[11] Thus, the opportunity to increase energy efficiency is substantial, but will require the focus of stakeholders to overcome the barriers to adoption.

Large (commercial and industrial) customers, being focused on profit, are savvier than the residential class as to their awareness of cost-saving opportunities. Given capital availability constraints, however, commercial customers tend to demonstrate high return-on-investment hurdle rates (i.e., short payback periods) to invest capital in activities not directly related to their core product or service offering. This factor limits implementation of investments that would be of long-term benefit to the customer specifically and for society overall.

Policymakers and regulators are clearly intent on promoting customer choice of energy supply and increased renewable energy output. Twenty-nine states have Renewable Portfolio Standards (RPS), 24 states have energy-efficiency resource standards and 43 states have net energy metering.[12] Yet the approach to realizing this objective has primarily relied on customers taking the initiative to investigate new opportunities or responding to utility mailers regarding pilot programs, which are adopted by a very low percentage of customers. While there are many providers in various markets that are seeking to sell their technologies and services, customers often don't know whom to trust in this complex arena and are not familiar with the alternatives.

Why not engage utilities and offer them incentives to assist in accelerating these objectives? Utilities are well positioned to assist their customers in learning about and deploying energy-saving technologies, but they need both increased incentives and accountability for doing so. What we see from the success of smartphone applications ("apps") is that customers want "low-touch" solutions that can be implemented and monitored with ease. While that may not be possible for all services, the smartphone app

8 Solar Electric Power Association, 2014 Power Statistics

9 Edison Foundation Institute for Electric Innovation, "Summary of Electric Utility Customer-Funded Energy Efficiency Savings, Expenditures and Budgets", (2014).

10 EnerNoc Utility Solutions Consulting, "Factors Affecting Electricity Consumption in the U.S. (2010–2035),"), (2013).

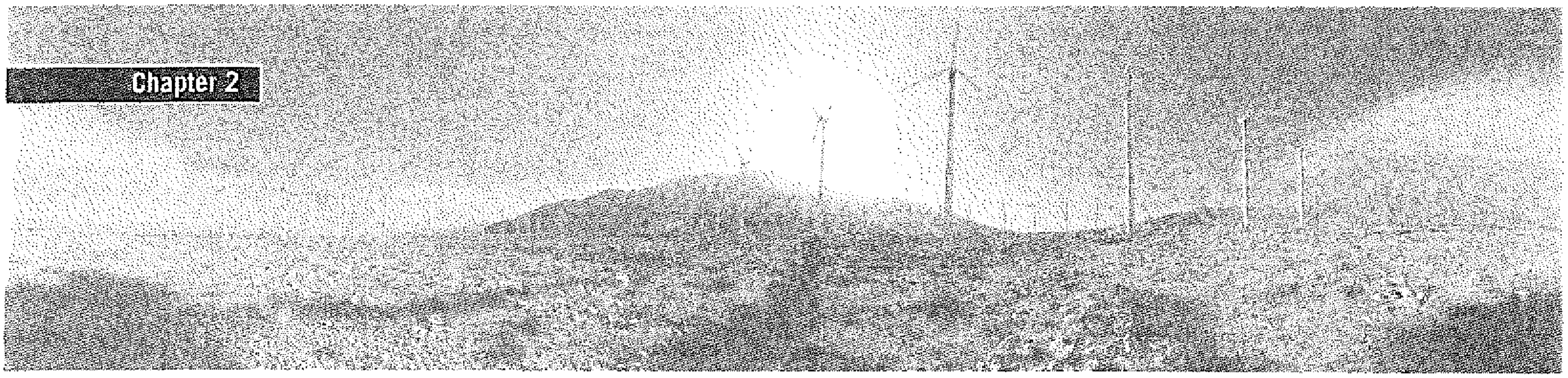
11 ACEEE, "Energy Efficiency in the United States: 35 Years and Counting," June 2015.

12 ACEEE website, State Energy Efficiency Planning.

is today's gold standard for engaging customer interest. The exciting news is that the advancement of sensor technology and automated controls is creating new possibilities for low-touch efficiency applications in the energy sector (e.g., Nest, a learning, programmable thermostat).

Many observers believe that there is a meaningful aversion on the part of regulators to determining how utilities should be compensated for providing such new services. Thus, the utility role is neglected in favor of competitive industry players, who are *not* well known by customers, to drive this important objective. In fact, there is a logical scenario, to be outlined later, in which competitive third-party providers collaborate and partner with utilities to accelerate the adoption of their products and services.

Finally, although utilities are interested in providing excellent service to customers, they also have a fiduciary obligation to support their investment value by earning a fair economic return on the capital employed in the business. In most jurisdictions, utilities earn revenues based on capital invested, and such revenues are recovered through customer usage. By promoting activities that reduce usage, utilities are working against one of their core missions and their fiduciary duty, which is to earn a fair return on invested capital. Thus, achieving stakeholder objectives regarding energy efficiency and clean-energy technologies may be best accomplished by providing incentives to customers and providers. In most business models, businesses are motivated to sell new services because this enhances revenue. In our present utility business model, utilities realize a "penalty" to their revenues by encouraging the deployment of our current policy objectives, such as energy efficiency. This creates an inherent conflict that requires logical solutions, such as "revenue decoupling," described later, which breaks the link between energy sales and revenue, to align utility and customer interests.



A Vision for the 21st Century Electric Utility

If we could start with a clean sheet of paper, how would electric utility services be structured? We would want to ensure that there was alignment of policy, customer and investor goals in order to structure a product offering that satisfied the best interests of all major stakeholders, a win4. Such a service offering would maintain and build on the high electric reliability we have today; allow customers to benefit from the latest, most economical technologies to optimize the efficiency of their energy service; be environmentally friendly; and seek efficient economic deployment of resources and, thus, capital investment.

Policymakers would seek optimal economic deployment of the system to ensure reliability and capital efficiency. They would expect deployment of resources consistent with local, regional and national environmental policy goals. They would ensure that price signals be provided to customers so that the system was used efficiently to manage systemwide costs (both embedded and future deployment). Finally, policymakers would want to see fairly stable customer prices, to provide customers more certainty and help realize a competitive cost of service that promoted economic growth in the region.

Utilities in this optimal environment would aim to offer a suite of products and services to achieve customer and policymaker objectives, and they would earn at their cost of capital (as deemed appropriate by the marketplace), or be given incentives to earn above it, for meeting these objectives. In a transparent and predictable business environment the cost of capital is lower, and the availability of capital is greater, than for less transparent, less stable businesses. Investors seek a business that offers growth potential as well, because a business without growth offers only a bond-like investment.

Competitive service providers would partner and collaborate with utilities to refine their products, optimize customer-acquisition costs and increase their share of market. In other words, they would partner with utilities to enhance their collective profit potential. To aid in identifying opportunities, competitive providers might avail themselves of defined, non-customer-sensitive electric system data. Policymakers would decide what information could be provided without compromising customer and system security.

How would a 21st Century Utility operate? It would target optimal use of diverse (hydro, solar, wind, biomass, efficiency, demand response, storage and Combined Heat and Power (CHP) renewable or low-cost electric energy resources that would be backstopped and supported by other clean, baseload energy sources. This efficient deployment of renewables, consistent with a utility cost-effectiveness plan, would seek the most economical and location-efficient technology to provide the best resource base for the benefit of the entire system. For example, in addition to residential rooftop PV solar systems, which do not consider optimal location or technology efficiency, the resource base would include a significant component of DER, community or utility-scale solar, intentionally located to enhance grid and system efficiency. The system would look to include efficient deployment of demand response and microgrids in those areas where reliability was of paramount importance (e.g., regions with high concentrations of hospitals, senior centers and schools) to protect them from weather and other emergency events.

This efficient deployment of renewables, consistent with a utility cost-effectiveness plan, would seek the most economical and location-efficient technology to provide the best resource base for the benefit of the entire system.

Energy Management Applications Store

Over the past several years we have witnessed explosive success and customer interest in software applications that integrate with smartphones and tablets to provide easy and fun access to powerful software tools. These apps provide an array of services and information at the touch of a button. Why not create a customer-focused energy management application page, or "store," that would allow customers to explore a range of product and service alternatives to save energy and money? The objective of such a store would be to:

1) introduce an available product or service alternative;
2) provide information to educate the customer;
3) highlight quality vendors to provide the service, as appropriate;
4) provide click-through to order the product, arrange for an estimate or get further information; and
5) monitor results from using the product.

Ease of access to robust information and service ordering would be effective in engaging and empowering customers. Customers could be offered demand response, load management and time-of-use products that could be operated from their smartphone or other device. "My Dashboard" icons could support "shadow billing" to assess the potential savings from efficiency applications and other service opportunities. Customers' ability to arrange for the installation, operation and oversight of these services would be as easy as the touch of a button. Their total savings would be presented on the app so that they could see the benefit of their actions and understand how their usage and savings opportunities compare to their neighbors. This vision is not futuristic, because such tools and products exist today. The 75 percent of Americans with smartphones (expected to reach 80 to 85 percent by December 2015) or 87 percent with Internet connections would be able to access these services easily.[13]

The question remains: Who is best positioned to host the energy management app store—the government, the utility or some other sponsor? There is no reason that such an approach need be exclusive to one provider. The challenge is how to achieve the most traction from such an effort and create an environment in which customers have confidence that the information is objectively presented. Given an objective of increasing customer adoption of new technologies, utilities appear best positioned to be a logical host of this application store. They have the ability to provide usage data and objectively present information on services. In addition, utilities are best positioned to track and aggregate results of products and services to present to current and potential customers.

Policymakers would have to decide how to compensate utilities for providing this service. The Apple model is worthy of consideration. Apple hosts the App Store on its system and earns a fee from application developers (e.g., competitive energy solution providers) when users download apps. In the energy management model, third-party providers could compensate utilities for each customer click or purchase of a product or service. This model would likely result in a cost-effective tool for third-party providers to reach customers.

Importantly, the energy management application store by itself will not be sufficient to drive results without continued efforts by third-party providers to develop new efficiency technologies and by policymakers and utilities to design programs and customer education initiatives.

Figure 8: Energy Management Applications Store

13 comScore, "U.S. Smartphone Market Share Report,", February 2015.

Incentives would optimize expenditures and thereby moderate customer rate increases to help reform the utility model and manage behaviors. By realizing efficiency and system-load optimization, and considering tools such as the UK's Totex (see **Experiences in Selected States and the UK**, page 25), we should be able to moderate capital investment levels. For utilities, these incentives will offset reduced growth opportunities for investors and, most important, encourage the achievement of customer and policy objectives.

The challenge is that we are not starting from a clean slate, and while we have an excellent quality of essential utility service, the shift to the 21st Century Utility model requires complex transitions that will be heavily debated by stakeholders.

Examples of such transitional issues include:

- phasing in new clean-energy resources while phasing out less clean resources;
- phasing out current subsidy structures for DER users to an economic-value-driven incentive model;
- enhancing customer engagement in pursuit of optimal use of efficiency resources through continued focus on awareness, education and customer incentive programs; and
- regulatory reform to align interests, incentives and metrics for achieving accountability of results.

In order to achieve these goals, we need to create a transition plan that embraces the end-state vision. For that we need policy leadership, clear goals, alignment of interests and accountability.

The vision for the 21st Century Utility can be summarized in four simple points:

- enhanced reliability and resilience of the electric grid while retaining affordability;
- an increase in cleaner energy to protect our environment and global strategic interests;

Technology Game Changers

Although it is a mature industry, the electricity sector has become increasingly dynamic. New forms of technology are in development that will significantly shape the future of the utility business. Given the large capital investment required to fund this sector, and its essential and pervasive involvement in our communities, an important consideration to factor in to the development of the 21st Century Utility industry framework is how customers and utilities will deploy and address new technologies, including those on the horizon that have not yet achieved commercial viability.

Policy will be an enabling driver of many of these game changers. Policymakers should be proactive in considering how best to accelerate each of these opportunities in a 21st Century Utility model to maximize their potential economic and environmental benefits. Potential game-changing technologies such as the following could dramatically reshape the utility business.

- **Grid scale and customer-owned battery storage units** allow electricity to be stored when not required for immediate use and thereby dramatically enhance the value of intermittent resources, such as solar and wind power. They also allow customers to buy power from the electrical grid when prices are lowest and use their own energy at more expensive times. This is a technology-driven opportunity.
- **Electric vehicles** create potential for substantial additional electric demands (expected to be off-peak) for charging batteries and could discharge energy back into the system when the charge has more value as a pure electric energy source. This is a technology-, policy- and customer-preference-driven game changer that could significantly reduce pollution from the transportation sector.
- **Combined heat and power** standards for all large, continuously deployed energy loads (hospitals, hotels, prisons, etc.) optimize BTU consumption by leveraging waste heat into electric energy and steam-heating loads. This is a policy-driven game changer using incentives.
- **Enhanced building standards** can promote energy efficiency and strive to reach net-energy-neutral status. This requires policy to mandate that new construction and remodeling achieve higher efficiency standards. According to a study prepared for the IEEE, aggressive building codes and standards would achieve a 17 percent reduction in electric usage by 2035.[14]
- **Appliance standards** can compel all new major energy-using appliances to operate at best-in-class efficiency levels and support Internet adoptability for purposes of controlling technology use. This is a policy-driven game changer.
- **Big data analytics** can be leveraged to enable intelligent efficiency technologies. This is a technology- and policy-driven game changer.
- **Cost-effectiveness planning protocols** can be applied, both for resources and systemwide, including renewable adoption, promoting the most efficient resources to provide systemwide benefits. This is a policy-driven game changer.

Most of these game changers will allow for more efficient deployment of system resources (e.g., storage, CHP, building and appliance standards). While electric vehicles will increase off-peak electric consumption, they offer the opportunity for storage optimization. All of these listed items will require incremental capital investment, either on the grid or behind the meter.

14 EnerNoc Utility Solutions Consulting, "Factors Affecting Electricity Consumption in the U.S. (2010–2035)," (2013).

- optimized system energy loads and electric-system efficiency to enhance cost efficiency and sustainability; and
- a focus on customer value, including service choices and ease of adoption.

Reliability and Resilience

Few question the priority and importance of enhancing the reliability and resilience of electric service. While our electric system is highly reliable, recent weather events and the reliability needs of our increasingly technology-dependent economy are ample proof that we require exceptionally high reliability and resilience to fuel our economy. As in most areas of strategic importance, we cannot just maintain the status quo, but must be committed to continuous improvement of our electric system to support new technologies and the competitiveness and growth of our economy.

Increased Clean Energy

Most Americans believe that preserving a clean environment and addressing climate change are essential priorities. Gallup polling shows that only 24 percent of Americans have no concerns as to the quality of the environment (which is down from 29 percent in 2010).[15] Opposition to developing a cleaner energy mix tends to highlight the near-term economic impact (jobs and costs to customers), but momentum is clearly building toward a cleaner energy mix. In support of a clean energy future, (i) 36 states plus D.C. have either renewable portfolio standards (29 states plus D.C.) or renewable portfolio goals (7 states), (ii) 23 states have energy efficiency resource standards, and (iii) the US EPA recently released the Clean Power Plan (which aims for a 32 percent reduction in greenhouse gas emissions by 2030).[16]

Optimized Energy System

Optimizing the use of our energy infrastructure will enhance our economic growth potential by increasing customer discretionary income and reducing costly energy emissions. Optimization of resources includes efficient energy consumption, spreading usage to off-peak periods and reducing the need to invest in incremental energy infrastructure. In doing so, current and future costs of electric service can be proactively managed to enhance value for customers. System energy loads should be optimized, not simply

Optimizing the use of our energy infrastructure will enhance our economic growth potential by increasing customer discretionary income and reducing costly energy emissions.

Con Ed's Brooklyn-Queens Program

An interesting example of deploying innovative solutions to achieve the goals of a 21st Century Utility is Con Ed's Brooklyn-Queens Demand Management Program (BQDM). The BQDM seeks to reduce demand by 52 megawatts via customer-side and utility-side solutions in order to avoid spending $1 billion on a new substation and related electric infrastructure. This initiative will provide incentives to participating customers and to Con Ed and will result in lower utility rates for all customers.

individual customer energy loads. For example, if there are better ways to enhance the efficiency of the grid (vs. behind the meter), all customers benefit equally from this investment. Examples include community solar and grid-level storage, as compared with customer DER application of such technologies. *This is not to suggest that we mandate one renewable resource over another, but that we pursue the most cost-efficient energy sources, either through new-construction plans or by capping incentives on DERs consistent with the most cost-effective clean-energy options.*

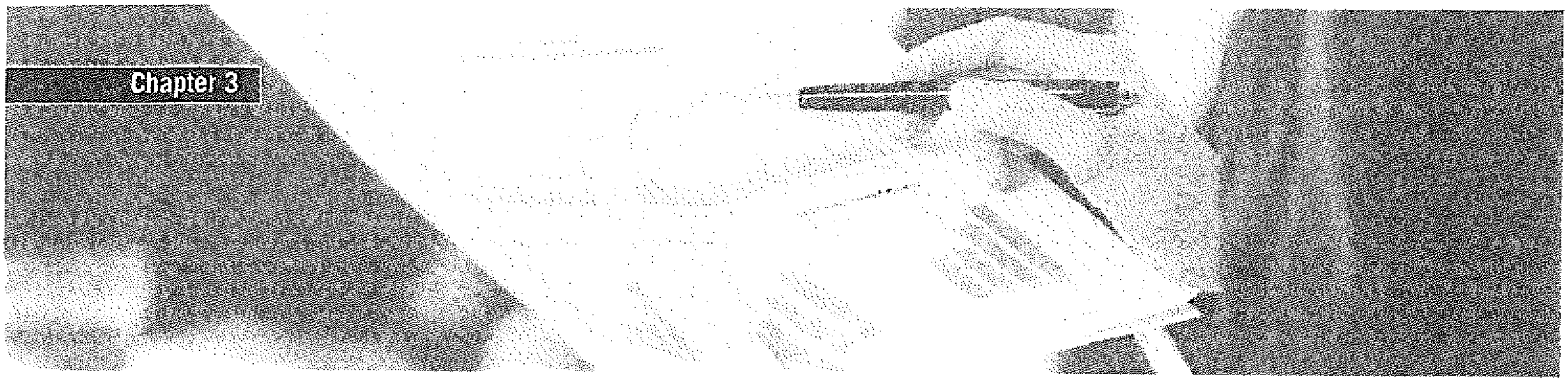
Customer Value

This is a new area of focus for utilities. Prior to DER and efficiency applications, utilities were responsible for meeting system needs, and customers were viewed as "ratepayers." When customers have alternatives, service providers must focus on providing customer value. Utilities are in the process of transforming to customer-focused organizations with an expanding choice of energy technology options. This is a work in progress, and many utilities may not understand the significance of this change. The focus on customer value also includes ease of product adoption. We live in a complex world in which many interests compete for our time. Value to customers is not just about product quality and cost of service, but includes making it easier for customers to learn about and, if appropriate, adopt alternatives.

To build such an industry, we will need foundational principles to support the vision and a pathway to reach it.

15 Gallup, Gallup Social Series: Environment, March 2015.

16 ACEEE website, State Energy Efficiency Planning.



Foundational Principles to Support a 21st Century Electric Utility

A durable building or organization requires a strong foundation to support its structure. The prior section outlined the vision for a 21st Century Utility industry, but we cannot create this without solid foundational principles, which are as follows:

- financially viable utilities are essential to fund and support an enhanced electric grid;
- policymakers must promote clear policy goals as part of a comprehensive, integrated jurisdictional energy policy or 21st Century Utility model;
- a commitment to engaging and empowering customers can help them make intelligent energy choices, including third-party engagement and access to necessary data; and
- equitable tariff structures promote fairness and policy goals.

Financial Viability

Enhancing our electric grid to achieve our reliability objectives will require significant investment. The Brattle Group estimated that $75 to $100 billion per year (in 2009 dollars) will be required to maintain reliability levels. The industry, however, has operating income of $30 billion per year before paying dividends, which means it needs access to external capital to raise the significant funds (in excess of $50 billion per year) to support the existing business and make the required future investments. Accessing capital of this magnitude requires investment-grade credit ratings (BBB- or above, using Standard and Poor's parlance). The better the financial health of the utility, the larger its potential audience for capital and the lower the cost of capital realized. Thus, financially healthy utilities are a key foundational component of a 21st Century Utility model. Importantly, financial health is built over many years of experiencing a transparent and durable operating environment, with consistent policies and financial performance.

Clear Policy Goals

The utility industry cannot evolve without rules and regulations that support the desired evolution. Thus, policymakers must assess the landscape and create, through active interaction with key stakeholders, clear policy goals and a program to achieve them. Each jurisdiction will need to fully explore the interests of stakeholders, the policy objectives already in place and the impacts of proposed policy shifts on their stakeholders. The objective is to develop a comprehensive and integrated set of policies that drive toward the desired outcomes while accounting for constraints to reaching the vision. Although several states are exploring the opportunity to refine their utility model (see **Experiences in Selected States and the UK**, page 25), no state to date has implemented an integrated, comprehensive set of policies, with a timeframe and plan to reach an objective. Without a comprehensive set of policies and a plan, a jurisdiction may have a variety of programs, some mandated and others aspirational, to refine utility services. But such plans require appropriate incentives and accountability as a comprehensive package to drive reform.

Customer Empowerment

A commitment to empowering customers to make intelligent energy choices may seem obvious, but it requires proper alignment of stakeholder interests. Traditionally, utilities have been motivated to sell electricity, not support reduced consumption or investment. We need to remove the model bias that promotes traditional utility financial value and create an environment in which all stakeholders are aligned and benefit from behaviors consistent with the vision. When shared interests are recognized, we have an opening for an environment that supports customer value creation, including promoting actions and tools for customers.

Equitable Tariff Design

Utility tariff structures will be a key component of the strategy to achieve a 21st Century Utility. Tariffs are central to both customer value decisions and recovery of revenues to support utility financial health. The development of tariff structures that support policy-driven objectives and that are fair to all customer classes is a key area of debate. In a model that focuses on efficiency and cost of service, inclining block rates have been a favored tool to mitigate excessive energy use. The problem for utility revenues is that this rate structure feeds customer choice dynamics that reward DER selection and transfers costs to non-DER customers. In the discussion of tariffs that follows, a package of solutions is proposed that is intended to encourage policy goals, fairness to all customer classes, systemwide cost optimization and utility financial stability.

Planning to Accelerate and Coordinate Industry Evolution

The U.S. has more than 50 state/district regulatory authorities overseeing investor-owned utilities, which represent over 70 percent of the U.S. electric industry.[17] To enable the industry to evolve, states have generally taken the approach of setting goals (e.g., RPS) and programs but rely on utility mandates or the competitive marketplace to innovate and provide solutions directly to customers, with the expectation or hope that customers will engage in these products and efficiency behaviors. If we rely on the marketplace to support the future of electric services, the most successful competitive market participants will win, but they may not be the most efficient for customers or society overall, as evidenced by the relatively low penetration of and energy savings from efficiency technologies.

To drive our electric energy future so as to optimize our finite resources (energy and capital), it seems appropriate for policymakers to proactively develop a comprehensive vision and plan for each jurisdiction's energy future. The objective would be for us to take charge of our direction and accelerate the efficiency of activity, and thus mitigate any waste of energy and capital through the transition of the plan to the desired end state. The components of a statewide energy or 21st Century Utility plan would include:

- **vision**—how we expect customers to use and manage their electricity needs in the future;
- **objectives**—comprehensive, integrated policy positions to achieve the vision, including the approach to deploying renewables, storage, DER and microgrids;
- **defined goals**—providing metrics and timeframes for achieving progress toward the realization of the vision;
- **clear participant roles**—who will be held accountable for driving the vision, and how customers, policymakers, utilities and competitive service providers will interface and cooperate;
- **incentives**—quantifying the appropriate level and approach to allocating financial incentives to stakeholders to accelerate and realize the vision;
- **accountability**—ensuring the realization of the vision through metrics, incentives and penalties; and
- **feedback loop**—how often the plan will be evaluated to reflect changing market dynamics and opportunities.

Given their scale, presence and interaction with all stakeholders, particularly customers, utilities appear to be the only logical entity to coordinate and be held accountable for the execution of a 21st Century Utility model and the realization of milestone goals.

Essential to the evolution and acceleration of a 21st Century Utility is the education of customers on the opportunities and benefits of optimizing their energy use (reducing use and/or moving load off-peak), deploying alternative technologies to optimize usage and offering assistance in adopting such new services. The more effective the education and ease of effort to adopt and utilize new services, the more likely that customers will be receptive.

While utilities have offered energy-efficiency programs and services for years, the Internet and smartphones are accelerating customer education and energy optimization. Smartphone apps turn what used to be low-priority chores into fun ways to be productive and share success and opportunities with friends. So although utilities have been involved with efficiency in the past, technology is driving exciting new products and services, and smartphone deployment is making it easier to adopt and manage these new technologies.

17 EEI, EEI website.

The Clean Power Plan

The EPA's newly issued CPP offers states an excellent opportunity to develop their energy strategies for achieving a 21st Century Utility business model. Issued in August 2015, the long-awaited rule governs performance standards for greenhouse gas emissions from existing and new power-generation sources. The CPP outlines the first national standards for CO2 emissions from power plants and seeks to reduce emissions from the power sector by 32 percent in 2030 from 2005 levels. Among its benefits, the CPP aims to improve health by reducing pollutants, supports clean-energy innovation and provides the foundation for a national climate change strategy. Compliance commences by 2022, with phase-in completed by 2030.

While lawsuits have already been filed against the rule, when implemented the CPP will be based on three building blocks: (i) improved performance of existing coal-fired power plants, (ii) substitution of natural gas power generation for coal-fired capacity; and (iii) increased renewable generation to an estimated 28 percent of our energy mix by 2030.

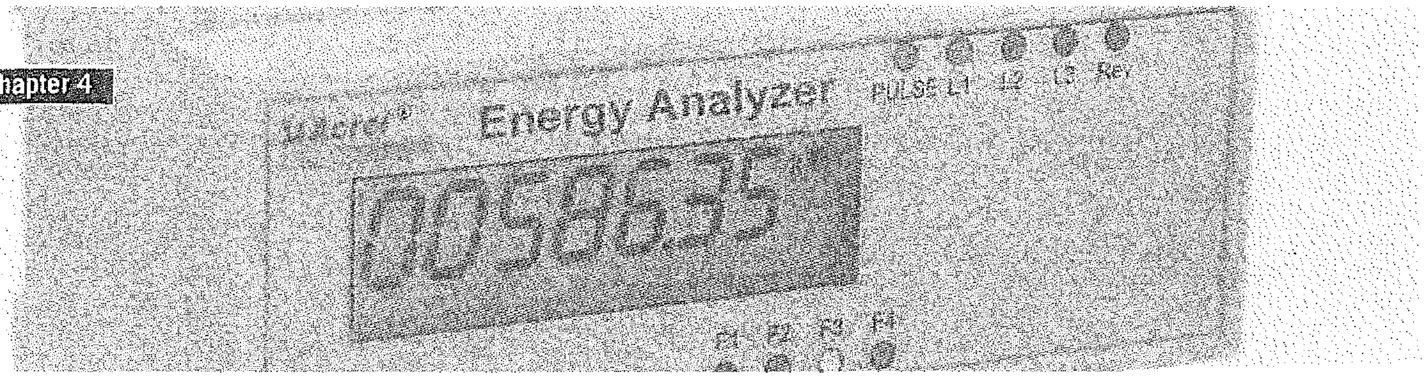
Each state is responsible for developing and implementing a plan that ensures compliance through the phase-in. States have the option to implement plant-specific performance plans or a statewide portfolio approach. While end-user energy efficiency is not a formal building block in the rule, it is allowed as a compliance option. States can also join together to develop multistate solutions, such as the Regional Greenhouse Gas Initiative. The rule calls for state plans to be filed by September 2016, with the potential to seek extension until September 2018.

The timeframe set for state CPP compliance plans provides an excellent opportunity for each state to develop its energy strategy in alignment with the 21st Century Utility model proposed in this paper.

While the CPP provides significant flexibility to states, the rule will likely lead to reduced coal-fired power generation and a significant expansion of renewables to achieve the targeted CO2 emission reductions. For renewable power generation to grow from 13 percent of our power mix in 2013 to 28 percent in 2030 will require a dramatic increase in renewable-energy capacity and investment.

States will likely consider multiple strategies to encourage an increase in renewable energy, including expansion of RPS mandates to support their CPP implementation plans. Based on projections developed from Energy Information Administration (EIA) data, the renewable capacity required to generate the 2030 goal could stimulate up to 350GW of incremental renewable capacity. This level of capacity expansion will require all forms of renewables to be adopted, but utility-scale renewables will likely be a very large component of the compliance requirement, given their scaling potential and economic advantages.

The timeframe set for state CPP compliance plans provides an excellent opportunity for each state to develop its energy strategy in alignment with the 21st Century Utility model proposed in this paper.



The Pathway to a 21st Century Electric Utility

Stakeholders will likely agree on the vision and foundational principles to support a 21st Century Utility model, but the way to achieve it will be more heavily debated. This paper introduces a pathway for accelerating the realization of a 21st Century Utility by setting clear policy direction, assigning accountability for results and shifting the focus of regulatory oversight from litigated rate proceedings to forward planning and accountability with incentives and penalties. The following pathway points are not an á la carte menu of choices but are intended to be a combined package of actions to support and integrate realization of the vision.

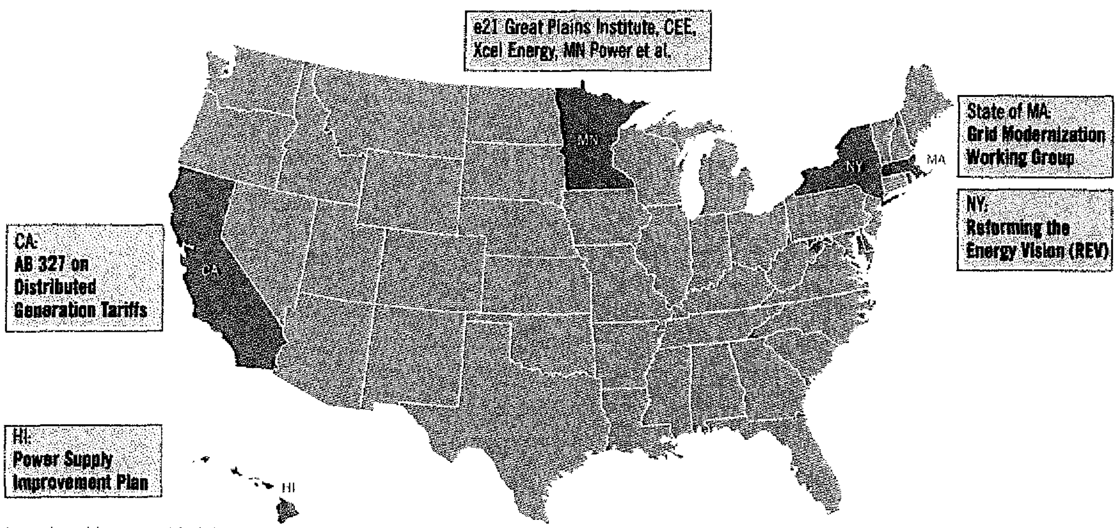
- State policymakers pursue legislation to outline the model for a 21st Century Utility, to include:
  - providing environmental, RPS, energy-efficiency, demand response and peak-load management objectives, including transitional targets;
  - refining building standards to address new construction and major modifications to support efficiency and environmental footprint goals (e.g., California Zero Net Energy Plan for new construction);
  - accountability metrics for managing the transition to the vision;
  - reform of the regulatory oversight approach to focus on planning and accountability oversight; and
  - outlining the role by which distribution utilities will be authorized to participate, including the potential for service revenue and behind-the-meter asset ownership.
- Regulatory reform is enacted to support efficient resource deployment and accountability:
  - multiyear integrated transmission and distribution system planning process, including defining the value and cost-effectiveness of renewable options;
  - transparent and sustainable accountability metrics to be set, based on customer and policymaker objectives;
  - transparent and sustainable incentives (and penalties) for accountability as to realization of policy objectives;
  - multiyear rate proceedings to target customer focus and shift of resources from regulatory administrative proceedings to planning and results accountability; and
  - structure of utility revenue potential for integrating new customer services and potential for ownership of DERs, including revenue requirement implications.
- Tariff structures are refined to support price signals and financial viability requirements, including:
  - inclining block rates to encourage efficiency and signal incremental cost of new resources;
  - bidirectional meters installed for all DER customers;
  - transition to highest economic value renewable rate:
    - most economical option to meet RPS, adjusted for transmission and distribution investment, line losses, system reliability and emissions avoidance value, and
    - timing of transition and grandfathering of existing DERs;
  - demand response to be bid into capacity planning to encourage load resource optimization; and
  - time-of-use rates to be implemented to manage peaks and enhance system optimization.
- Utilities are empowered and accountable for managing the transition, and are:
  - held accountable for controllable results in achieving a 21st Century Utility;
  - encouraged to lead the integration of new technologies and given incentives to achieve results, as deemed appropriate;
  - responsible for educating customers on new energy management alternatives; and
  - the potential owners of renewables, new technologies, or DERs, as addressed in statewide energy or 21st Century Utility plans.

Experiences in Selected States and the UK

States with high electric prices, locational DER opportunities or grid reliability challenges will likely take the lead in pursuing 21st Century Utility proceedings and, hopefully, implementation programs. Clearly, states will develop policies and strategies that reflect their unique circumstances regarding policy, system resource issues, locational opportunities and energy costs. Many states will learn from first-mover jurisdictions that are pursuing a 21st Century Utility model in a comprehensive manner.

While practically every state has addressed specific issues related to energy supply and efficiency programs, few have developed a comprehensive framework for engaging the utility of the future. California and New York have been the most proactive in leading change in their markets. Also worthy of note is the Revenue = Incentives + Innovation + Outputs (RIIO) model in the UK and how it has addressed the alignment of customer, policymaker and utility interests. In Minnesota, policy advocacy and utility interests have proposed an interesting paradigm to develop the electric utility model and are in the process of collaborating with state policymakers to discuss the proposed framework, referred to as the e21 Initiative.

Figure 9: Responses to Evolving Electric Utility Models



Source: Great Plains Institute, July 2015.

California has led efforts to reform its utility model, dating back to an aggressive Public Utilities Regulatory Policy Act implementation program in the 1980s and its groundbreaking 1994 industry-restructuring docket. However, the California energy crisis of the summer of 2002 illustrated that not all that has been tried in California has met with success. Still, California has led with its aggressive implementation of renewables through its RPS (now seeking a 50 percent renewable mix by 2030), attracting both rooftop and utility-scale renewables, and energy-efficiency spending (about 30 percent of U.S. spending).[18] California also leads on incentive programs for utilities to achieve efficiency savings and programs to enhance energy-storage technologies, though the incentives for efficiency adoption are modest relative to the amount needed to drive significant organizational focus and strategy.

Currently, California is mandating that distribution resource plans be provided by each utility, with a focus on better integrating DERs into the grid. However, California has not gathered its array of programs into a comprehensive 21st Century Utility model, and is only beginning to unleash the full power of its nearly statewide advanced metering infrastructure, including meaningful residential customer application of time-of-use rates. Policymakers are facilitating change through mandates, due to California's high electric prices and their willingness to allow cross-subsidies among and between customer classes. Such mandates raise questions as to the fairness of benefits to all customers, given the small but growing percentage of customers who take advantage of market opportunities, such as rooftop solar rewarded with high net energy metering buy-back rates.

18 Edison Foundation Institute for Electric Innovation, "Summary of Electric Utility Customer-Funded Energy Efficiency Savings, Expenditures and Budgets", (2014).

New York has been the most active in pursuing a comprehensive solution to a reformed utility model. The New York state proceeding Reforming our Energy Vision (REV) intends to promote more efficient use of energy, including increased penetration of renewables and DERs. It also intends to promote markets to drive greater use of new technologies for energy management. The objective is to empower customers by providing more choices for managing their electric consumption. Utilities, under REV, will be tasked with operating the grid and acting as the distribution-service platform provider, integrating market solutions into the grid. The New York Public Service Commission (NYPSC) is considering tariffs and incentives to better align utility interests with achieving the commission's policy objectives. The Staff of the Department of Public Service issued a white paper[19] in July 2015 proposing future incentive opportunities for New York utilities, including market-based earning opportunities from new grid-related services and incentive mechanisms for performance consistent with goals. The REV initiative is a work in progress.

Neither California nor New York has yet created material, timely or transparent incentive frameworks to move utilities to revise their approach to customer engagement, or otherwise taken a leadership position to encourage large percentages of the customer base to more proactively optimize energy consumption. In New York, that is starting to change. Con Ed's BQDM Program, discussed earlier, is a recent example of the NYPSC approving an innovative solution that does provide for incentives to the utility.

If the system can benefit from efficiencies related to operating versus capital expenditures, the utility will earn a return on a component of such efficiency savings while the customer benefits from a lower cost.

In California, the incentives available two years after the reporting period yield less than 1.25 percent of utilities' operating income.[20] This level of incentive does not motivate major corporate strategic reassessment of operational, financial and compensation strategies. In addition, the programs in California and New York do not promote the most efficient use of DERs, but encourage the marketplace to adopt DERs, at the same time discouraging the utilities from investing in them by offering attractive net energy metering incentives.

Minnesota's e21 Initiative is an interesting and important collaborative effort to develop Minnesota's 21st Century Utility. The effort is led by the Great Plains Institute, an energy policy advocacy group, and involves Minnesota's investor-owned electric utilities and several national energy policy groups. The initiative proposes a comprehensive framework for a 21st Century Utility and regulatory oversight approach. The Phase I report, issued in December 2014, includes the following recommendations:

- reward utilities for delivering customer value with reduced reliance on a capital investment–driven model;
- align the utility model with state and federal policy goals;
- enable the delivery of services that customers value;
- fairly value grid and DER services;
- focus on economic and operational efficiency of the entire system;
- reduce regulatory oversight–related administrative costs; and
- facilitate innovation and implementation of new technologies.

e21 proposes performance-based ratemaking as an incentive to utility performance, consistent with multiyear integrated system plans that focus on DER deployment and reducing costs through system wide efficiency measures. The initiative seeks to establish multiyear rate programs to shift the regulatory oversight focus from rate-case preparation and deliberation to forward planning.

The e21 Initiative, while in its early stages, represents a comprehensive and collaborative approach to pursuing a 21st Century Utility model. Unlike New York's REV, this initiative is more robust in that it provides a larger role for utilities to engage with customers and it outlines how regulatory oversight should evolve. For the initiative to move forward, policymakers will need to endorse the framework outlined. How this initiative is ultimately received by Minnesota policymakers, and the full range of public process participants that engage in the discussion, will shed light on the prospects for policy-led collaboration toward a new utility model, in Minnesota and nationally.

The **United Kingdom's RIIO** model is encouraging to consider for its impact on ratemaking solutions. The RIIO model builds on the UK's prior approach to determining revenue. It will create eight-year periods for price review, under which utilities have the opportunity to realize operational efficiencies, subject to accountability metrics, and given incentives to consider operating investments that replace or defer capital investment (known as Totex, or total expenditures). Totex was structured to address the inherent utility bias toward capital investment (rate base) by capitalizing and allowing a return on, and of, investment of certain operating expenditures that avoid or defer less economical capital investment. The concept is to focus on optimizing total system expenditures. If the system can benefit from efficiencies related to operating versus capital expenditures, the utility will earn a return on a component

19 State of New York Department of Public Service, "Staff White Paper on Ratemaking and Utility Business Models," July 28, 2015

20 SEC Form 10-K for Edison International and PG&E Corporation

of such efficiency savings while the customer benefits from a lower cost. The criticism of RIIO is that significant regulatory proceedings, costs and ongoing oversight are required to approve and execute on a RIIO planning period. So, while the RIIO model may not be appropriate for many U.S. states due to the significant administrative burdens created for policymakers and utilities, components of RIIO, such as multiyear regulatory review periods and Totex, are worthy of consideration for implementation.

Developing an Accountability and Incentive Framework

The utility model we operate within today is highly regulated and mostly backward looking in its approach to regulation. In an ideal world, policymakers would outline their policies and develop accountability metrics to monitor and evaluate utility performance. Instead of mandating and overseeing countless proceedings as to utility performance, a strategy could be employed by which reasonable accountability metrics were tied to meaningful incentives and penalties that would lead utilities to focus on achieving best-in-class performance. Since U.S. utilities for the most part already provide best-in-class reliability of service, new accountability metrics would focus on achieving performance toward a 21st Century Utility framework. Examples of potential accountability metrics, focusing on customer and policy goal realization and the transparency and sustainability of such goals, are as follows:

The utility would **not** be responsible for developing new technology, but for assessing and working with technology providers to bring best-in-class technologies to the customer base.

- **reliability**—percentage of hours of uninterrupted electric service and percentage and number of annual outages impacting customers;
- **service**—range of customer energy solutions offered, number of customer calls, call wait times and number of calls to resolve complaints;
- **efficiency**—weather-adjusted decline in energy usage due to efficiency adoption and peak load management and optimization;
- **clean energy mix**—increase in renewables and DERs and decline in carbon footprint relative to RPS standard transitional goals; and
- **investment**—capital and total spending below a predetermined rate, subject to carve-out for critical infrastructure investments.

To be effective in driving change, incentives and penalties must be transparent (i.e., easy to understand, calculate and report on in a timely manner). To drive and align behavior change, significant opportunity and dollars should be at risk for achieving on incentive performance, for example up to 10 to 20 percent of profits. A utility realizing a 10 percent ROE would be able to earn up to 12 percent for meeting its incentive targets. While there is no science behind that incentive number, it must be meaningful to encourage changes in behavior, and less than 10 percent is unlikely to achieve that goal. In order to encourage the behavior and innovative spirit that are essential to achieving continuous performance improvement, incentives must be durable. They must be available and achievable on an ongoing basis and subject to revisions as market conditions evolve. For capital markets to differentiate between those states that provide incentives and those that do not, durability will be an important component.

The benefit of a multiyear regulatory plan is that utilities can align their strategy with the implementation of their integrated distribution plan, which will free up resources that can be deployed in effective future planning because fewer resources will be required to process rate cases. Transparent accountability metrics and resulting incentives and penalties will provide ongoing oversight of utility performance and progress in reforming our energy future. Policymakers, through their regulatory oversight, can ensure that the integrated system plan responds to their stated objectives. In particular, agreement can be solidified on deploying and valuing renewables, such as community solar and rooftop solar. A robust integrated system plan would provide utilities with an effective roadmap for operating over the planning period with improved clarity as to the path of utility rates over that period. Each new integrated planning cycle would provide an opportunity to refine the next plan, so as to continuously improve the process and respond to customer and marketplace dynamics.

Engaging Utilities to Adopt a 21st Century Electric Utility Model

The pathway proposed in this paper looks to the utility as the facilitator, integrator and nonexclusive distribution channel to offer new products and services to its market. The utility would **not** be responsible for developing new technology, but for assessing and working with technology providers to bring best-in-class technologies to the customer base. With the support of policymakers, utilities may be allowed to own and operate (either through the regulated entity or an unregulated affiliate) assets behind the meter, or at a minimum, could leverage competitive providers to offer the best price to customers. The advantage of utility ownership is scale and cost of capital benefits.

The following summarizes why utilities should be at the forefront of leading, integrating and accelerating the transition to a 21st Century Electric Utility, from the perspective of key stakeholder interests.

Benefits to Customers

- high level of recognized trust in utility providers versus a large group of unknown vendors of competitive energy services and technologies (including efficiency, demand response, load management and DER providers);
- access to customer and electric system information that supports a program for system optimization regarding future investment (subject to strong standards to protect consumer privacy);
- increased quality control oversight of third-party competitive energy service providers and products, given their scale, system knowledge, resources and lack of incentive to promote one new technology over another;
- enhanced information analytics based on customer usage experience to support customer decision making regarding innovative energy-optimization product alternatives; and
- lowest systemwide cost of deploying optimal located investments with scale technologies.

Benefits to Policymakers

- acceleration of defined policy objectives (efficiency, system optimization, environmental) through properly structured incentives and accountability for realizing results;
- ability to enhance accountability via regulatory oversight of utilities; and
- opportunity to mitigate the level of utility rate increases required by allowing utilities to earn additional revenues related to facilitating, integrating or owning new services, including behind-the-meter assets.

Benefits to Competitive Marketplace Service Providers

- endorsement of best-in-class providers and technologies;
- partnering with utilities can facilitate increased adoption of new value-add technologies; and
- partnering with utilities can reduce customer acquisition costs and thus enhance profitability (through reduced cost and increased volumes).

Benefits to Utilities

- enhanced customer service by increasing interactions with customers;
- optimized investment and reduce costs and risks;
- enhanced regional economic growth through enhanced optimization of utility system and services;
- enhanced citizenship profile;
- potential to earn incentives for achieving accountability goals; and
- ability to earn additional revenues from participating in facilitating and integrating realization of a 21st Century Utility, thereby creating potential to offset rate-increase needs and earn incremental returns for investors.

Those opposed to utilities owning behind-the-meter assets within the regulated business fear that it could: (i) complicate the regulatory model and ratemaking, (ii) increase potential financial risk to customers for un-creditworthy decisions and (iii) freeze out competitive industry players. Policymakers/ stakeholders would have to evaluate these issues when considering whether and how to allow utilities or utility-affiliated entities to participate in behind-the-meter infrastructure.

We now have an array of competitive entities seeking to offer new electricity products and services to both residential and large commercial and industrial customers. This is a positive development, but there is little, if any, oversight of the quality of the services offered, including the economic efficiency of these new inputs to the energy delivery system. Third-party entities partnering with utilities should create the right type of checks and balances by which utilities can oversee the development of new technologies that impact their system, invest as appropriate to support the grid needs and enable best-in-class technologies, and act as a distribution channel to assist in deploying new technologies. However, competitive service providers may seek utility system data to support their initiatives, and policymakers will need to resolve issues regarding data control, sharing and privacy protection.

Regulators in this paradigm would be able to drive utility accountability through appropriate and transparent customer and policy performance standards, consistent with the objectives of economic provision of reliable, clean and affordable energy services. In addition, regulators would determine how utilities would be compensated for their role in facilitating change and customer adoption through incentives, as well as penalties when performance standards are not met. They could further offer commissions for utilities facilitating sales of new products offered by vendors, and structure compensation and returns allowed on utility (or utility affiliate) ownership to allow for behind-the-meter assets.

Utilities have been timid in claiming a role in accelerating and executing a 21st Century Utility model. Several factors have likely caused a less than aggressive posture: skepticism on the part of regulators, who often suspect that utilities may earn outsized profits from future activities and, thus, have sought to encourage the competitive marketplace **without** providing rules for how utilities can participate; a strong lobbying effort by competitive market providers to prevent utilities from participating in new services; and utility compensation programs aligned with fiduciary duties that do not encourage development of new markets but focus on reliability and near-term financial performance.

Vertically Integrated vs. Restructured Utilities

Given the restructuring of U.S. electric utility markets and utilities' roles in 17 jurisdictions during the 1990–2005 period, the industry is no longer a homogeneous group of vertically integrated (distribution, transmission and generation) utilities. In most restructured markets, distribution utilities own no meaningful level of power generation and thus are less exposed to threats to the economics (and value) of the power markets. The volatility and profitability of power generation in restructured markets is borne by competitive generation companies (whether independent from utility ownership or in unregulated utility-affiliate entities). However, to the extent utilities in restructured markets collect tariffs based on energy usage, these transmission and distribution utilities remain exposed to fluctuations in customer energy usage. Thus, not all utilities will be impacted by the same set of factors in the transition to a 21st Century Utility sector.

Importantly, the highest-cost markets that are seeing the most interest in efficiency and new technologies tend to be in restructured regions. Thus, we expect that these markets will tend to be at the forefront of driving industry change.

Because vertically integrated utilities own power generation, they are more exposed than transmission ad distribution utilities to the electricity consumption impacts of DERs and various forms of energy efficiency. Declining consumption for these companies results in lower revenues to recover generation investment and the related adverse impact on market power prices (due to lower demand and increasing supply from DERs). Thus, all other factors aside, it is likely that electric generation owners, including vertically integrated utilities and competitive generators, will be less interested in moving toward a 21st Century Utility until the level of unrecovered investment in power-generation assets becomes less meaningful. This does not suggest that a transition may not occur prior to recovering greater levels of generation investment, since regulators can approve structures, such as transition charges, to accelerate change if they deem it appropriate. In fact, the e21 Initiative was developed for adoption in Minnesota, which is a vertically integrated utility market.

Utilities in restructured states have less at risk in moving forward with a 21st Century Utility sector. While these utilities may still be exposed to kWh consumption-based tariffs, the impact can be more easily managed by decoupling or other mechanisms to mitigate any drag on return on invested capital. Importantly, the highest-cost markets that are seeing the most interest in efficiency and new technologies tend to be in restructured regions. Thus, we expect that these markets will tend to be at the forefront of driving industry change.

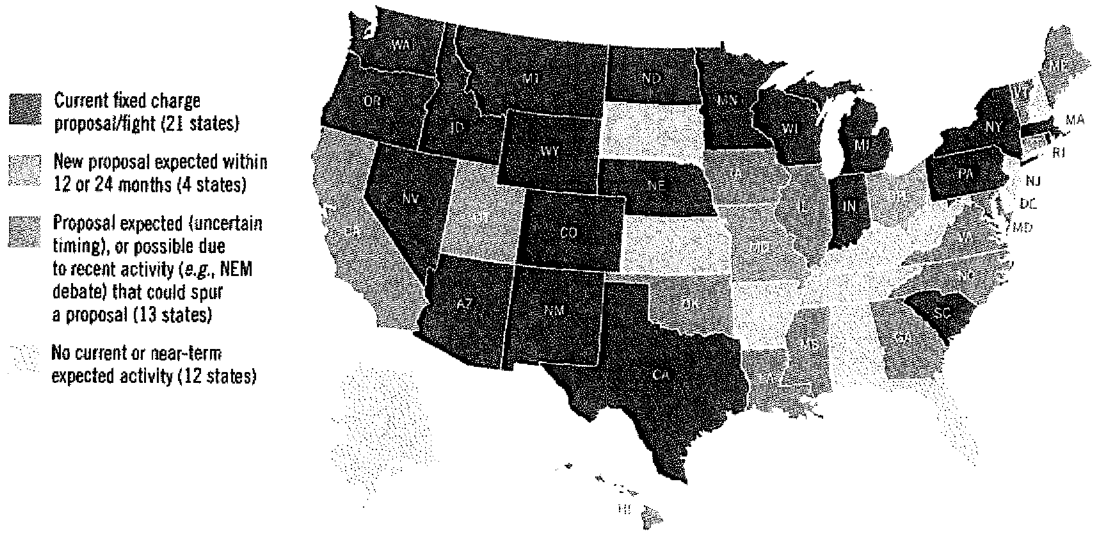
Ratemaking and Tariff Design

Important components of the evolution to a 21st Century Utility industry model are the topics of ratemaking and tariff design. For purposes of this paper, ratemaking is defined as the process by which regulators determine the appropriate aggregate annual revenue collection (or revenue requirement) utilities may recover from customers to cover costs and earn a fair return on invested capital. Tariff design refers to the structure of customer rates (or prices charged) to recover the revenue requirement allowed.

Ratemaking, which is grounded in legal precedent as to the utilities' right to recover prudent costs, is not a hotly contested issue in the 21st Century Utility debate. The ratemaking discussion has often focused on structuring a system whereby utilities have no incentive for (or are indifferent to) increased capital investment (aka rate base) to provide service, such as in the UK's RIIO model.

Tariff design is the tool that regulators use to promote policy objectives, such as equitable distribution of cost, customer usage and consumption behavior. "Disruptive Challenges" highlighted the confluence of factors challenging the long-term financial viability of our traditional utility regulatory model. The strategies proposed to address and mitigate the disruptive forces outlined were primarily regulatory solutions. Looking through an investor's lens, several tariff-restructuring alternatives were proposed. Those alternatives, which could be implemented individually or in combination, included increasing monthly fixed charges on all customers, monthly service charges for all distributed energy resource (DER) customers and/or

Figure 10: Mandatory Fee Proposals Timing Map



Source: NRDC, NCLC and Vote Solar.

revising the net metering buy-back rate to be based on the wholesale value of the energy provided by the DER customer to the utility (versus the retail rate, as reflected in the majority of net energy metering programs).

Marketplace dynamics since the release of "Disruptive Challenges" suggest that two important factors were missing from that 2013 assessment: (i) the customer and policymaker view that it is not in the best interest of customers or society overall to slow the pace of technology innovation or adoption (a likely result of increased customer fixed charges), and that over the long term, technology advancement cannot be deterred by regulatory rulemaking; and (ii) customer and policymaker actions through 2015 that have demonstrated a clear policy opposition to meaningful increases in fixed charges, as evidenced by low fixed charges in place throughout the investor-owned utility industry, as well as recent actions in several states that approved nonmaterial fixed charge tariffs (e.g., Arizona Corporation Commission adopting a $5/month charge, not the $50/month charge proposed by Arizona Public Service).

While the cost structure of distribution and transmission of electric utilities is predominantly of a fixed nature (i.e., not meaningfully impacted by volume variability or short-term business issues), utility rate structures have typically authorized a small fixed charge component. Increasing mandatory fixed charges (or demand charges), a solution proposed in *"Disruptive Challenges,"* is a tariff design tool that utilities have actively pursued since 2013 to mitigate revenue risk from disruptive forces. According to the Environmental Law and Policy Center, **24 utilities have recently proposed increases to their fixed fees.**[21] However, significant increases have met with strong opposition from customer interests and policymakers.

Adopting meaningful monthly fixed or demand charges system-wide will reduce financial risk for utility revenue collections for the immediate future, but this approach has several flaws that need to be considered when assessing alternatives through a win4 lens, by which all principal stakeholders benefit. Fixed charges:

Adopting meaningful monthly fixed or demand charges system-wide will reduce financial risk for utility revenue collections for the immediate future, but this approach has several flaws that need to be considered when assessing alternatives through a win4 lens, by which all principal stakeholders benefit.

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

While DER customer charges can be structured to reflect

21 Environmental Law and Policy Center Foundation, June 2015.

the value of the grid connection that is maintained by practically all DER customers, such charges will need to consider whether and at what level a DER buy-back rate (the price paid for energy by a utility to a DER supply customer) should be set. Through a win4 lens, it is clear from recent regulatory actions reconfirming support for DERs and net energy metering that policymakers are interested in DER development and customers want the option to choose their own energy supply.

It is therefore in the long-term best interests of utilities to support such choice, consistent with regulatory policies that support financial viability and avoid meaningful monthly fixed charges. By instituting monthly DER customer grid fees or reducing buy-back rates, it is likely that rooftop solar activity will be slowed, and this must be considered in the policy debate. This is consistent with the early experience of the Salt River Project (SRP), which is not regulated by the Arizona Corporation Commission and implemented a $50/month renewable customer grid charge for all new rooftop installations. Since that announcement, one major rooftop supplier reported a 96 percent decline in new solar applications in the SRP territory.

Besides the installed cost advantage of utility-scale solar versus rooftop solar and system optimization considerations, community or utility-scale solar brings the advantage of renewables to all customers without the potential cross-subsidy issues associated with rooftop solar.

Given the new tools available to enhance system wide efficiency, including peak load management, time-of-use rates can be an important tool in managing a dynamic optimization of resources as market demand and supply evolve in a technology-enhanced 21st Century Utility model.

Tariff Design Principles for a 21st Century Electric Utility

As we consider fairness to all customers, we should provide incentives to fund the most cost effective renewable options. In October 2015, the Hawaii PUC halted its net energy metering program for new systems due to penetration in excess of 20 percent. This is the first significant action to slow the growth of rooftop solar penetration due to the high cost that NEM programs shift to non-DER customers. In a recent study prepared by the Brattle Group entitled, "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area," the findings demonstrate that "utility-scale PV system is significantly more cost-effective than residential-scale PV systems when considered as a vehicle for achieving the economic and policy benefits commonly associated with PV solar. If, as the study shows, there are meaningful cost differentials between residential and utility-scale systems, it is important to recognize these differences, particularly if utilities and their regulators are looking to maximize the benefits of procuring solar capacity at the lowest overall system costs."[22]

Given the significant net cost benefit of approximately 45 percent for utility-scale solar (due to capacity costs and power output optimization), pricing of rooftop solar and related subsidies, and other energy technology alternatives, should be determined by the most efficient alternative opportunity, after factoring in grid-related costs and benefits. Tariff fairness can be structured, such as by adopting renewable grid charges or adjusting DER buy-back rates (i.e., net metering), in a way that factors in the economic value of adding renewables to the grid and creates an opportunity for all customers to benefit equally from the adoption of renewables, not just homeowners who can deploy solar on their rooftops.

Without increased demand for electricity sales, fixed charges to all customers, or DER grid charges, utilities will continue to be exposed to customer switching and under recovery of revenues. This is especially true for utilities with inclining block tariffs (i.e., the more you use, the higher the rate for incremental energy consumed) that are in excess of the cost of DER alternatives. The result of ongoing customer adoption of DERs in net energy metering states (43 of 50) is that future rate increases are required to offset the revenue lost from those customers adopting DERs. This scenario feeds a cycle of customer adoption of DERs and eventually results in increasing rates for non-DER customers. The advent of (i) bidirectional metering, (ii) most economical value of renewable buy-back rates and (iii) revenue-decoupling mechanisms can assist in mitigating this risk.

Time-of-use (or real-time) pricing has the potential to be an important tool in optimizing system capacity and moderating incremental capital investment in electric energy infrastructure. While this type of tariff design has been discussed for years and is supported by smart-meter technology investment, policymakers have generally not supported it. The lack of support from policymakers is a roadblock to moving forward on a 21st Century Utility model.

Time-of-use rates have not been widely implemented due to technical constraints—a lack of smart-meter

22 The Brattle Group, "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area," Prepared for First Solar, July 2015.

infrastructure—and a lack of public interest. Customer concerns include lack of understanding, potential volatility of bills, and impact on low- and fixed-income customers. Given the new tools available to enhance system wide efficiency, including peak load management, time-of-use rates can be an important tool in managing a dynamic optimization of resources as market demand and supply evolve in a technology-enhanced 21st Century Utility model. Thus, we need to expand our efforts to educate and pilot these programs. While "opt-in" programs have often realized low adoption levels, another alternative to consider is selected "opt-out" programs, where appropriate, to encourage realization of policy objectives.

Factoring in financial viability considerations and customer and policy preferences, the following tariff principles are components of a tariff design that can contribute to the development of a 21st Century Utility model:

- introducing inclining block rates to promote efficiency of energy consumption;
- decoupling of revenues from volumetric usage charges to protect cost-recovery shortfalls in the short-term, for example due to customers switching to DERs or declining usage due to new technologies; however, decoupling does not reduce the long-term vicious cycle of increasing customer adoption of DERs created by increasing rates;
- providing bidirectional meters to all DER customers so that energy consumed from utilities would be charged based on utility tariff schedules, and buy-back rates for DER-produced energy at a value of renewable rates;
- setting the value of renewable rates at the higher of competitive wholesale energy prices or the levelized cost of the lowest incremental cost to deploy efficient renewables (e.g., lower of rooftop vs. utility scale, with adjustments based on evaluation of system costs and benefits); and
- establishing time-of-use rates to optimize system efficiency; time-of-use rates will enhance the value of new technology investment as customers optimize the value of this rate structure (e.g., using appliances with time-of-use controls).

With these principles in place, tariff economists can fine-tune potential tariff structures to support a 21st Century Utility model. Each jurisdiction will have its own unique issues and cost structures that will impact the ideal approach in its market. Since we are likely to grandfather existing DER customers during the transition period, we should address the tariff issue now to define the ultimate transition period, provide fairness to all customers and mitigate financial risk to customers and utility investors.

Financial Issues

The financial health of utilities has improved over the last several years, based on the support of regulators for allowing recovery of revenue shortfalls due to declining consumption and customer growth, with increased use of decoupling of revenues from consumption in some form now in over 28 jurisdictions. In addition, a decline in the cost of fuel to generate power, lower merchant power prices and lower interest rates have provided additional headroom for base utility rate increases. In this environment, and reflecting lower interest rates in the financial markets, utility credit ratings have stabilized from the continuous decline experienced from the 1960s through 2010, and utility equity prices have been at or near all-time highs on a dollar price and multiples-of-earnings basis. Investors are generally pleased with the utility sector's performance, and likely hope the current business model prevails for the foreseeable future. Unfortunately, hope is not a strategy.

However, below the surface, lie foundational shifts that suggest the steady period of utility performance will be challenged by customer choice, the adoption of new customer-driven technologies and customer behavior changes driven by social and economic forces

However, below the surface, as described in countless industry trade articles and in "Disruptive Challenges," lie foundational shifts that suggest the steady period of utility performance will be challenged by customer choice, the adoption of new customer-driven technologies (e.g., Nest) and customer behavior changes driven by social and economic forces (e.g., smaller homes). Investors have shown from prior experiences in other industries that they become noticeably concerned about disruptive challenges when the loss of sales and revenues is reflected in financial results. For utilities, this can happen when serious rate-increase opposition accelerates due to the impact of increasing penetration of DER technologies.

Although these disruptive challenges are well outlined in utilities' SEC filings, utility managements are managing their businesses based on the current framework and their fiduciary duty to focus on quality service for customers and growth in near-term earnings and investment value for investors. As long as investment spending supports growth through increased rate needs, the problems lurking in the future are kicked down the road, although one could argue that the problems are amplified by increasing utility rates in the short term. In addition, utility management compensation is focused on near-term reliability and financial goals, creating a fiduciary obligation and compensation incentive for management to focus on the near term.

For the time being, all may appear well, but if one believes that risks are at play, when these threats become a financially reality, investment values will be impacted. Capital availability will decline as investors focus on the potential for declining profitability and the risk of stranded assets or cost levels that the remaining customer base may be unwilling to bear. Given the importance of utility access to capital to support the grid, this is not an acceptable scenario.

The objective is not to create fear or call for a death spiral, but to commence the transition now to a future that customers support and in which utilities can play a constructive role and access the capital required to build this future. As a point of reference, who would have thought that essential service industries in a growing economy such as the airlines and the landline phone business would not support investment-grade quality ratings as stand-alone entities?

The New 21st Century Electric Utility

The current transition of the electric utility framework into a new model is being led by economic and technological forces that will ultimately drive change. This is particularly true given the support of policymakers for customer choice of electric supply and new technologies to drive efficiency, system optimization and the reduction of our environmental footprint through expanding our mix of clean energy sources.

The actions by states to date in considering meaningful regulatory change have been predominantly in support of a free marketplace for competitive providers to offer their new services to customers directly or through utility-run efficiency programs. In that environment, the utility is relegated to grid provider, and policymakers have few levers to oversee or influence the marketplace to achieve their vision.

The environment that this paper proposes is one in which the utility is responsible for the development and operation of the grid, but is also encouraged and accountable for accelerating our progress toward a 21st Century Utility model. The utility will be encouraged and accountable for promoting the adoption of new technologies, and for developing a cost-effective plan to deploy technology in the most efficient way to control customer costs. In this scenario, cost of capital on new investments might consider returns on selected operational spending (similar to the UK Totex model) that mitigates less-than-optimal capital investment. Utilities would also play a traffic cop role by allowing only proven technologies or vendors entry to their application store.

Utility revenues will be determined by regulators to encourage a return on invested capital, particularly for the legacy system in place, and transparent incentives to encourage accountability for accelerating change and policy realization. It may be a challenge to develop tariff mechanisms and incentives, since there exists a distrust of providing utilities an opportunity to increase their returns above currently allowed levels. But common sense and economic theory demonstrate that the best way to achieve results is to provide economic incentives. Regulators will continue to regulate, and thus any midcourse correction deemed necessary can be implemented. The objective is to develop a formula by which customers are served, policy is realized, technology adoption and product offerings by competitive entities is accelerated, and utilities are motivated to achieve the objectives of customers and policy while maintaining financial viability to support the grid.

Concluding Comments: Transitioning to the New Utility Model

The transition to a new industry paradigm will require the proactive support of customers, policymakers and utility regulators, competitive-market service providers, and utilities. In the ideal world this would be a collaborative process, driven by policymakers who understand that the industry model needs to be refined in order to promote the full suite of opportunities that can be created by a 21st Century Utility. A mutual understanding of the benefits of collaboration and economic benefits to all parties is key to a productive process and for defining a clear transition and end state.

Figure 10: The Pathway to a 21st Century Utility Model Vision

Vision:

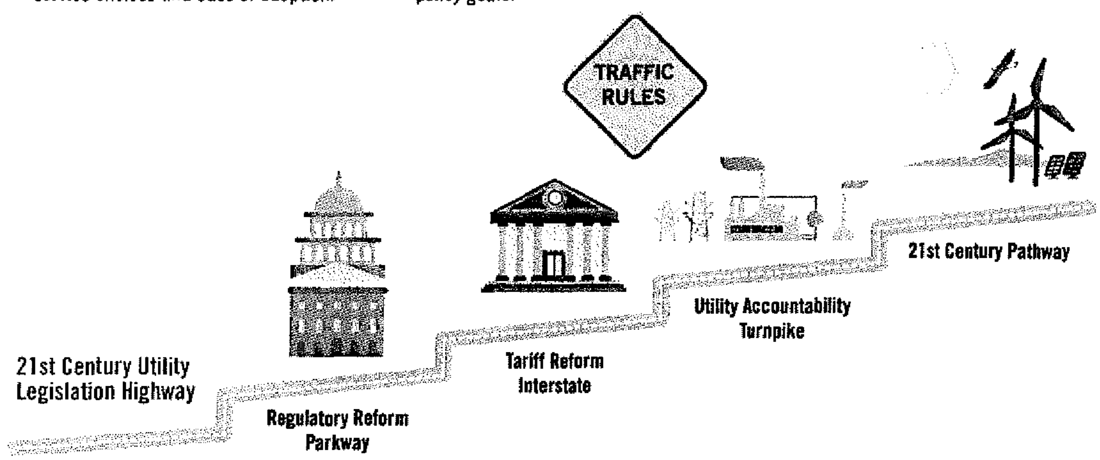
- Enhanced reliability and resilience of the electric grid while retaining affordability;
- An increase in cleaner energy to protect our environment and global strategic interests;
- Optimized system energy loads and electric-system efficiency to enhance cost efficiency and sustainability; and
- A focus on customer value, including service choices and ease of adoption.

Foundational Principles:

- Financially viable utilities essential to fund and support an enhanced electric grid;
- Policymakers must promote clear policy goals as part of a comprehensive, integrated 21st Century Utility Model;
- Commitment to engaging and empowering customers to make intelligent energy choices; and
- Equitable tariff structures that promote fairness and economic and environmental policy goals.

Pathway:

- State policymakers pursue legislation to outline the model for a 21st Century Utility;
- Regulatory reform to support efficient resource deployment and accountability;
- Tariff structures refined to support price signals and financial viability requirements;
- Utilities empowered and accountable for managing the Transition.



To make progress, it is important to begin this transition soon and oversee its continual evolution. The process to accomplish this transition is not regimented, but should include the following steps:

- define the objectives, vision and foundational principles for a 21st century electricity market;
- identify the transitional constraints and roadblocks to navigate to the end-state market;
- consider the roles and interactions of key market participants, including utilities and competitive service providers;
- define utility tariff structure objectives and approaches to realizing objectives;
- identify alternative incentives and hold utilities accountable for accelerating and integrating system optimization;
- define a timeline for commencing the study process and transition to the end state;
- identify a process to revise the utility model through the transition, as appropriate; and
- define the impact of the new model on the regulatory oversight process.

No two states will apply the same approach, but the goal is to develop several robust models that can be tested and compared against each other to refine into best-in-class models over time. The policies set forth for a 21st Century Utility model and the pathway for achieving results will create a significant opportunity for economic growth and regional competitiveness. Over the long term, these proactive solutions will create shared benefits for customers, utility investors and society as a whole.

The policies set forth for a 21st Century Utility model and the pathway for achieving results will create a significant opportunity for economic growth and regional competitiveness.

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company and Nantucket Electric Company in their petition for approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq	)	**D.P.U. 15-155**

AFFIDAVIT OF TIMOTHY WOOLF

Timothy Woolf does hereby depose and say as follows:

I, Timothy Woolf, certify that the attached direct testimony and related exhibits on behalf of the Energy Freedom Coalition of America, LLC, which bear my name, were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury as of this 18th day of March, 2016.

Tim Woolf

Timothy Woolf

COMMONWEALTH OF MASSACHUSETTS
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AFFIDAVIT OF MELISSA WHITED

Melissa Whited does hereby depose and say as follows:

I, Melissa Whited, certify that the attached direct testimony and related exhibits on behalf of the Energy Freedom Coalition of America, LLC, which bear my name, were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury as of this 18th day of March, 2016.

M. Whited

Melissa Whited